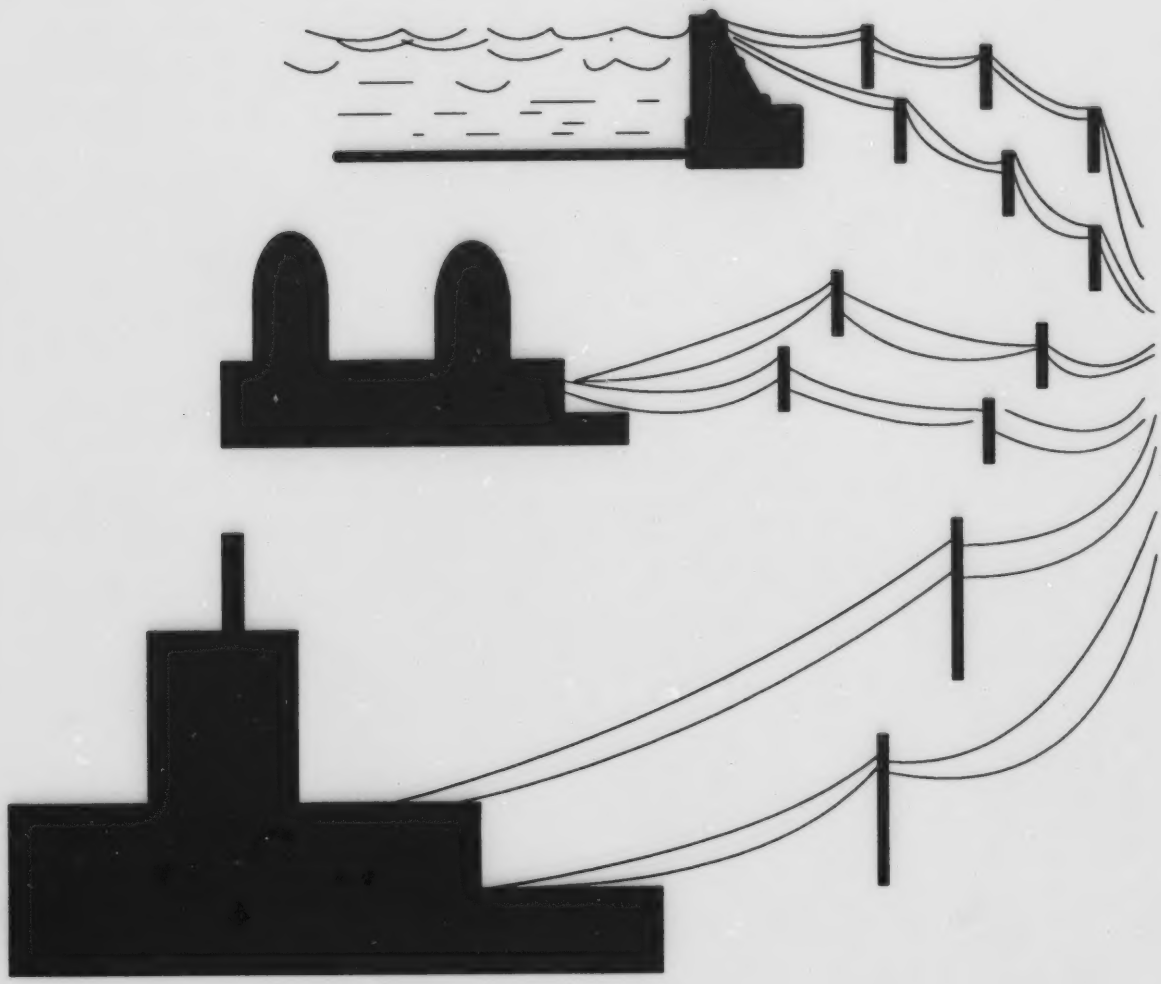
COMPARATIVE COSTS OF GENERATION IN NORTH AMERICA

CANADIAN REGIONAL COOPERATION AND DEVELOPMENT OPPORTUNITIES



National Energy Board
ELECTRIC POWER BRANCH
JANUARY 1992

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CANADIAN REGIONAL COOPERATION AND DEVELOPMENT OPPORTUNITIES

1. INTRODUCTION

The Federal government's September 1988 "Canadian Electricity Policy" focused on new initiatives respecting the regulation of electricity exports and the construction and operation of international power lines. In that year the Federal government also established an Energy Options Advisory Committee whose purpose was to canvass Canadians in order to develop a comprehensive energy options plan for the nation into the next century. In its report entitled "Energy and Canadians into the 21st Century" which was released in the fall of 1988, the Committee stated that "the Government of Canada has a crucial leadership role to play in eliminating barriers to interprovincial trade". The Committee made two particular suggestions.

- "Electrical energy generation should be organized on a cooperative interprovincial scale when economically viable.

- The Government of Canada should articulate the conditions under which one province has a right to access, on a business basis, another province's electricity corridor or electrical grid for the purpose of transmitting electricity to a market not adjacent to the first province".

The Federal government acknowledged that a number of difficult practical and jurisdictional questions must be addressed before it could decide whether it was necessary to take specific policy actions in these areas. Accordingly The Federal Minister of Energy Mines and Resources requested the National Energy Board to undertake a review and report on possible measures that could properly be taken to:

- enhance interprovincial trade in electricity

- encourage greater cooperation between utilities in systems planning and development

- enable buyers and sellers of electricity to obtain commercial access to available transmission capacity through intervening provinces for wheeling purposes

In undertaking this review, the Board decided to carry it out along two separate tracks. The first focussed on inter-utility cooperation. The second addressed questions relating to wheeling and transmission access.

As part of the review, a number of staff studies and assessments by outside consultants were prepared to help focus on the benefits of inter-utility cooperation and wheeling both from a qualitative and quantitative perspective. The purposes of these reports were to promote dialogue and stimulate discussions on these important electric power matters with interested parties in Canada.

This paper, by Board staff, focuses on the comparative cost of generation in Canada and selected regions in the USA to obtain an indication of enhanced inter-utility cooperation and development opportunities among Canada's electric utilities which would lead to increased economic, reliability and security benefits for those utilities and for Canada as a whole.

2. STUDY APPROACH

2.1 Geographic Area Studied

Most Canadian electric utilities are interconnected both interprovincially and internationally. Therefore any study on Canadian regional cooperation and development opportunities in electricity, must of necessity, take into account the potential for Canada/US trade in electricity.

As figure #1 shows, most Canadian utilities are members of the North American Electric Reliability Council (NERC) which comprises nine Regional Reliability Councils and one Affiliate encompassing virtually all of the electric utility systems in the United States and Canada. Canadian Utilities in BC and Alberta are members of the Western Systems Coordinating Council (WSCC), those in Saskatchewan and Manitoba are members of Mid-Continent Area Power Pool (MAPP) and those in the provinces of Ontario, Québec,

FIGURE 1

North American Electric Reliability Council

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

RELIABILITY, in a bulk electric system, is the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply for service to customers.

Bulk electric system reliability can be addressed by considering two basic and functional aspects of the bulk electric system — adequacy and security.

ADEQUACY is the ability of the bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

New Brunswick and Nova Scotia belong to the Northeast Power Coordinating Council (NPCC). Only utilities in Newfoundland &, Labrador and Prince Edward Island do not have membership in NERC.

Thus for such a study to be meaningful it was necessary to examine the potential for both interprovincial and international trade opportunities among Canadian and US electric systems within the three NERC regions.

2.2 Study Method

A utility's primary objective is to minimize its total system cost of electricity to customers within its service area. Thus before electric utilities make decisions to commit capital, which can run into billions of dollars, for expanding their generation supply and transmission networks to meet their increasing demand requirements, they determine their minimum cost supply scenario using sophisticated generation optimization models. Since Canadian utilities are generally provincial crown corporations with mandates to serve the electrical needs of the provinces, these generation expansion plans are usually oriented to exploit the natural resources of the provinces with only secondary regard to possible generation developments on a regional basis.

Establishing the optimum generation expansion programs, on a joint basis, within the various regions in Canada requires a complexity and sophistication of analysis that was beyond the scope of this report. Moreover, even if such programs were developed, it is unlikely that they would in the end provide the broad based information required to influence policy makers on the ways and measures that might be required to increase inter-utility cooperation and interprovincial trade. The approach has therefore been to aim at providing a "broad brush" indication of the comparative costs of generation and ignores many factors which would be considered in a rigorous approach, such as, for example,difficulties in obtaining transmission rights-of-way.

This NEB staff study was based on the simple yet reasonable premise that, from an engineering economic viewpoint, after taking into account the potential for demand side management and conservation, utilities must meet their forecast increase in customer demands by adding new supply capability, either through building generation themselves or through purchases from others if the economics were attractive enough. This approach also presupposes that considerations of international and/or interprovincial boundaries,

regulations, and other factors such as the environment, employment impacts etc. although important would not alter that fundamental premise.

This assessment thus focused on the "Build or Purchase" question faced by utilities within the study area. Two fundamental elements were assessed. They were:

(i) The life cycle cost of generation and associated transmission facilities to bring the power to the market within each province and selected US States who might be potential purchasers of Canadian electricity. (These costs, referred to in this report as the levelized unit energy costs (LUEC) are described more fully in section 3.0 of this report).

The types of generation identified in each province or state were those considered to be good candidates in meeting the base load generating requirements of the respective utilities. For example, because of the potential hydraulic resources in the provinces of Québec and Manitoba, base load generation was assumed to be hydro. On the other hand, for Ontario, both nuclear and fossil fired thermal plants were assumed to be available to meet the demand requirements. In the US Midwest, because of the abundance of low cost lignite coal, the generation of choice was assumed to be lignite coal fired thermal plants.

(ii) The estimated annual capacity requirements (ACR) in each province and selected US States to meet the annual growth in demand. For this analysis, it was assumed that the demand in electricity would grow by 2%/year. These estimates thus provided an indication of the magnitude of the additional annual capacity that must be installed in each area, in order to meet anticipated demand growth while maintaining reliable and secure electric power.

Selected provinces and states were then grouped together to form what might be termed natural development regions. Within each region, the LUECs and ACRs associated with generating facilities in the particular provinces and states were then used to determine, on a notional basis, the comparative economic advantage or potential negotiating margins between systems in the region both from the point of view of interprovincial and international trade.

From these comparisons, general observations and conclusions were drawn about the relative economic potential for and possible barriers to increased inter-utility cooperation and development opportunities in Canada and North America.

3. DETERMINATION OF LEVELIZED UNIT ENERGY COSTS (LUEC)

LUEC can be defined as the constant unit energy price that has to be charged for each unit of energy generated over the life of the generating facility in order to exactly recover all capital and operating costs. Stated differently, the sum of the present value of all costs should exactly equal the sum of the present value of the LUEC multiplied by the present value of the energy generated over the life of the option.

To calculate the LUEC for any generating plant it was first necessary to obtain the overnight capital costs for the various types of generation within the major Canadian provincial utilities as well as utilities in the several US States who might be potential purchasers of Canadian electricity. These overnight costs were obtained from Canadian utilities, as well as from relevant publications and reports issued by utilities, federal, provincial and state agencies.

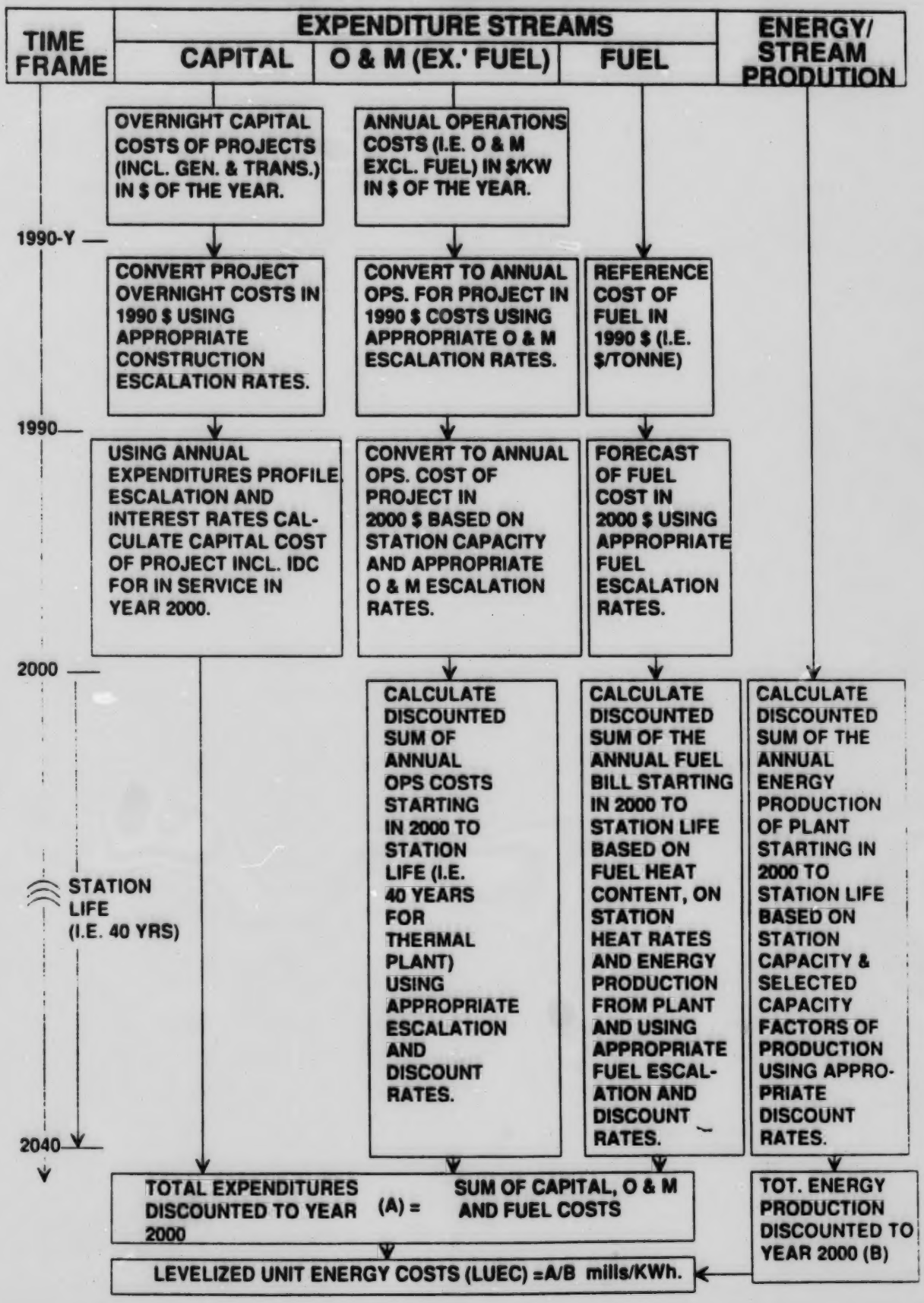
To make a proper comparative cost analysis between alternative supply sources, it was first necessary to convert these overnight capital costs on a common basis. All costs therefore were converted to 1990$. In addition, because the construction period associated with the various types of generation differed, it was assumed that all generation would come into service in the year 2000.

The total capital costs, including interest during construction, in current dollars for in-service in 2000 were next calculated based on a knowledge of the annual expenditure profile associated with each facility, the estimated inflation factors, and interest rates.

To these costs were added the associated operating costs, discounted to the year 2000. These costs included both operations and maintenance as well as fuel costs over the life of the plant. These O&M and fuel costs were estimated in constant dollars (i.e. 1990$) and then escalated to the dollars of the year the outlays were made. The cumulative expenditures were then discounted to the year in service (i.e. 2000) using a nominal discount rate, (i.e. 10.2% based on a real discount rate of 6%)

FIGURE 2

LEVELIZED UNIT ENERGY COST MODEL


TIME FRAME
EXPENDITURE STREAMS
CAPITAL
O & M (EX.' FUEL)
FUEL
ENERGY/ STREAM PRODUTION
OVERNIGHT CAPITAL COSTS OF PROJECTS (INCL. GEN. & TRANS.) IN $ OF THE YEAR.
ANNUAL OPERATIONS COSTS (I.E. O & M EXCL. FUEL) IN $/KW IN $ OF THE YEAR.
1990-Y
CONVERT PROJECT OVERNIGHT COSTS IN 1990 $ USING APPROPRIATE CONSTRUCTION ESCALATION RATES.
CONVERT TO ANNUAL OPS. FOR PROJECT IN 1990 $ COSTS USING APPROPRIATE O & M ESCALATION RATES.
REFERENCE COST OF FUEL IN 1990 $ (I.E. $/TONNE)
1990
USING ANNUAL EXPENDITURES PROFILE, ESCALATION AND INTEREST RATES CALCULATE CAPITAL COST OF PROJECT INCL. IDC FOR IN SERVICE IN YEAR 2000.
CONVERT TO ANNUAL OPS. COST OF PROJECT IN 2000 $ BASED ON STATION CAPACITY AND APPROPRIATE O & M ESCALATION RATES.
FORECAST OF FUEL COST IN 2000 $ USING APPROPRIATE FUEL ESCALATION RATES.
2000
CALCULATE DISCOUNTED SUM OF ANNUAL OPS COSTS STARTING IN 2000 TO STATION LIFE (I.E. 40 YEARS FOR THERMAL PLANT) USING APPROPRIATE ESCALATION AND DISCOUNT RATES.
CALCULATE DISCOUNTED SUM OF THE ANNUAL FUEL BILL STARTING IN 2000 TO STATION LIFE BASED ON FUEL HEAT CONTENT, ON STATION HEAT RATES AND ENERGY PRODUCTION FROM PLANT AND USING APPROPRIATE FUEL ESCALATION AND DISCOUNT RATES.
CALCULATE DISCOUNTED SUM OF THE ANNUAL ENERGY PRODUCTION OF PLANT STARTING IN 2000 TO STATION LIFE BASED ON STATION CAPACITY & SELECTED CAPACITY FACTORS OF PRODUCTION USING APPROPRIATE DISCOUNT RATES.
STATION LIFE (I.E. 40 YRS)
2040
TOTAL EXPENDITURES DISCOUNTED TO YEAR 2000 (A) = SUM OF CAPITAL, O & M AND FUEL COSTS
TOT. ENERGY PRODUCTION DISCOUNTED TO YEAR 2000 (B)
LEVELIZED UNIT ENERGY COSTS (LUEC) =A/B mills/KWh.

Next estimates of the discounted cumulative annual energy output of the plant over the life of the facility were calculated.

Finally the plant LUEC was calculated by dividing the total discounted expenditures from the total discounted cumulative annual energy outputs.

Further details are provided in Figure # 2 which illustrates the levelized unit energy cost model used in this study. Appendix 1 details the mathematical equations used to calculate LUECs and provides a sample computer printout for a typical power plant (i.e. Belledune #1). In addition Appendix 2 details all the economic and fuel costs assumptions used in the study.

It should be noted that the projections of discount rates, inflation rates and fuel prices used in this study are subject to considerable uncertainty; therefore users should consider them as illustrative rather than definitive. They generally lie within the ranges of data which the Board used in the 1991 Supply and Demand Report.

In putting forward these estimates, we do not imply that they are "most likely" outcomes. A range of projections above or below them is equally likely. Rather, this data is a starting point, the main usefulness of it being to develop a preliminary view of any large differences between the LUEC of the various options. For example we have assumed that the real price of coal decreases over time, while that of oil and natural gas increases. These divergent trends would drive wedges between the LUEC of the coal, oil and natural gas options, all else being equal. A key issue is the likely variance around these projections which is reasonable to contemplate for each fuel, and the impact of these variances on the comparative LUEC.

Over and above the data presented below, there are also considerable uncertainties associated with the capital costs of most power plants. For example, hydro costs are site-specific and not all utilities provide or know the detailed expected costs of developing future hydro sites. For coal technology, there are different ways of dealing with environmental protection, and we are at the early stage of developing experience in the use of these technologies. Nuclear plants are subject to particular capital cost uncertainty because safety requirements keep changing, construction periods vary from initial expectations and capacity availability factors are hard to predict over long time periods.

Finally in a study of this kind, it should be noted that it is the relative LUEC between options rather than the absolute level of any single one of them which is of particular importance. The study therefore focuses on the comparative LUEC between the various supply options and the development opportunities that might arise as a result of these cost differences.

4. STUDY RESULTS

The study results have been organized on two levels.

- The first level provides information about the cost of generation supply on a North American basis and focuses on the economic and other characteristics of the basic supply alternatives available to each province and selected U.S. regions.

- The second level provides an assessment of the regional cooperation and development opportunities that appear to exist from the standpoint of interprovincial and international trade.

The study results, observations and conclusions from a North American and regional perspective are detailed in the sections that follow.

5. NORTH AMERICAN PERSPECTIVE

Table #1 shows the economic ranking of the various types of generation in Canada and selected US regions.

Table #2 rearranges the information in Table #1 to highlight the correlation between the economic ranking and the type of generating units. Other factors, such as generation lead times required for the construction of facilities as well as various economic characteristics related both to the capital and fuel costs for such facilities have also been identified to provide a quick profile of the relative economic risks and uncertainties associated with each type of generation.

Finally Table #3 details the at market LUEC costs of generation by provinces and by selected US regions as well as the LUEC ratio of each plant referenced against the most economic plant in this study.(i.e. Alberta's Keephills sub-bituminous coal fired plant).

Figure #3 displays the LUEC information provided in Table #3 on an interconnected North American network basis showing both the international and interprovincial tie-line transfer capabilities (MW) under normal system conditions.

Figure #4 is similar to Figure #3 except that the economic ranking and LUEC ratios of the various generating units are displayed in lieu of the estimated plant LUECs. Figure #4 thus allows relative economic comparisons to be made between the estimated LUECs of specific plants. For example from Figure #4, the Lepreau #2 nuclear power plant in New Brunswick is estimated to be twice as costly as Alberta's Keephills plant.

Figure #5 shows the fuel component of LUEC for each plant on an interconnected North American network basis. Comparisons between the long run fuel costs of the various plants are indicative of the potential for economy energy interchanges and other system operating and coordinating benefits that could occur between systems.

Finally, Figure #6 shows the estimated annual capacity requirements (ACR) for each province and selected US regions to meet the anticipated annual growth in demand. ACR is indicative of the generation supply growth potential within systems and the resulting magnitude of the opportunities for trade both from an international and interprovincial perspective that may exist.

From an examination of the tables and figures the following general observations can be drawn:

- LUEC reflects the long-term economic cost of generation. (tables #1 to 3 and figures 3 & 4)

- Canada appears to have more supply options than the U.S. (table #2)

- In the U.S., hydro has been fully developed and no new nuclear plants have been ordered since the 1970's. This is not the case in Canada. (table #2)

- Alberta's coal fired generation is the most economic generation in Canada. This is followed by hydro in the provinces of BC, Man. Que and Nfld. (tables #1 & 2 and figures 3 & 4)

TABLE 1
Economic Ranking of the Various Types of Generation in Canada & U.S.

A - CANADA

Rank	Province	Description	Gen. Type	Fuel Used	MW Size	Operations (energy)	Nominal (1) LUEC (mills/KW.h) 2000 $
1	Alberta	Keephills # 3	Steam	Sub bit	375	80% CF	32.6
2	Nfld & Lab	Gull Island	Hydro	Water	2264	Average	39.2
3	Quebec	Brisay	Hydro	Water	460	Average	43.1
4	Manitoba	Conawapa	Hydro	Water	1300	Average	44.5
5	Manitoba	Wuskwatin	Hydro	Water	350	Average	44.7
6	Nfld & Lab	Muskrat Falls	Hydro	Water	820	Average	44.7
7	Quebec	La Forge # 1	Hydro	Water	820	Average	44.8
8	British Col.	Peace Site "C"	Hydro	Water	900	Average	46.3
9	Quebec	La Forge # 2	Hydro	Water	318	Average	46.4
10	Quebec	Grande Baleine #1	Hydro	Water	1000	Average	48.1
11	Ontario	Darlington B	Nuclear	Uranium	881	80% CF	48.7
12	Sask.	Shand # 2	Steam	Lignite	280	80% CF	48.7
13	Quebec	Sainte Marguerite	Hydro	Water	822	Average	49.5
14	British Col.	Hat Creek	Steam	Lignite	500	80% CF	50.2
15	Quebec	Eastmain	Hydro	Water	510	Average	50.7
16	Ontario	New Nuclear	Nuclear	Uranium	881	80% CF	55.1
17	Quebec	Broadback # 1	Hydro	Water	780	Average	58.4
18	Nova Scotia	Sheet Harbour (NS)	Steam	Coal	300	80% CF	66.5
19	N.B.	Grand Lake	Fluid. Bed	Coal	200	80% CF	67.6
20	Nova Scotia	Point Aconi	Fluid. Bed	Coal	150	80% CF	68.4
21	N.B.	Belledune	Steam	Coal	460	80% CF	69.6
22	Ontario	New Coal	IGCC (2)	Bit coal	600	80% CF	70.5
23	Ontario	New Coal	Steam	Bit coal	740	80% CF	70.7
24	N.B.	Lepreau # 2	Nuclear	Uranium	650	80% CF	75.6
25	Nova Scotia	Sheet Harbour (Exp	Steam	Coal	300	80% CF	90.6
26	Ontario	Hearn GS	C.C.	Nat. Gas	600	80% CF	90.3
27	Ontario	New C.C.	C.C.	Nat. Gas	600	80% CF	92.5
28	Nfld & Lab.	Holyrood # 4	Steam	Oil	150	80% CF	112.5
29	P.E.I.	Combined Cycle	C.C.	Oil	24	80% CF	154.4

B - UNITED STATES

16(US)	Mid West	Sherco # 4	Steam	Lignite	500	80% CF	55.8
25(US)	New York (3)	Sommerset	Steam	Coal	682	80% CF	76.6
25(US)	New England	New Coal	Steam	Coal	700	80% CF	80.1
25(US)	California	Combined Cycle	C.C.	Nat. Gas	390	80% CF	89.9
26(US)	New York (3)	Combined Cycle	C.C.	Nat. Gas	390	80% CF	93.5
28(US)	New England	Combined Cycle	C.C.	Nat. Gas	390	80% CF	101.5

(1) Economic comparisions based on nominal levelized unit energy costs (LUEC) at market (for generation in service in year 2000)
(2) Coal gasified combined cycle
(3) Assume ECAR costs similar to New York

- Gull Island is most economic hydro development in Canada (table #1 and figures 3 & 4)

- Lignite generation in BC and Sask is only a little more costly than hydro. (tables #1, 2 and figures 3, 4)

- The cost of lignite generation in the U.S. Midwest is close to Canadian lignite generation in BC and Sask. (table #2)

- Nuclear generation in Ontario is only a little less competitive than hydro and lignite generation in Canada (tables #1, 2)

- Coal-fired generation using bituminous coal is significantly more expensive than hydro, nuclear, sub bituminous or lignite coal generation. (tables #1 and 2)

- Coal-fired generation exists in the provinces of Ontario (using U.S. coal), NB and NS and in Michigan, Ohio (which is in the ECAR region), NY, and the New England states. Costs of coal fired generation in Canada and the U.S. are relatively equal. (tables #1 and 2)

- The more expensive types of generation in Canada and the U.S. are plants using natural gas and oil fuels. Principal advantages of these types of plants are the short lead times and low initial capital cost requirements. However, fuel costs are very high in comparison to other fuels. (tables #1 and 2)

- U.S. reliance on natural gas in California, NY and NE thus appears not to be driven by long-term economics, but by short lead times, low capital cost considerations etc. (table #2).

- Energy production costs (Fuel LUEC) are lowest for hydro generation (estimated at a nominal 1.0 mill/kW.h), in the provinces of BC, Manitoba and Québec. These provinces have a comparative advantage in economy energy sales over all other regions in Canada and the U.S. (Figure #5)

- Alberta's production costs using sub bituminous coal at 5.8 mills/kW.h compares favourably with NB's nuclear production costs at 3.0 mills/kW.h and Ontario's nuclear production cost at 7.1 mills/kW.h (Figure #5).

- Electricity production from bituminous coal whether in the U.S. or Canada is estimated to range from approximately 26-33 mills/kW.h. This is less than 50% of the cost of production using natural gas or oil which range from 70 to 85 mills/kW.h (Figure #5)

- Significant opportunities for economy energy export trade appear to exist using hydro, nuclear and coal fired generation in Canada to displace higher cost oil and gas fired generation in the U.S. (Figure #5)

- Opportunities for interprovincial economy energy trade on the other hand do not appear to be as great as those for export trade because of the relatively small amounts of expensive oil or natural gas fired generation in Canada available for displacement(Figure #5)

- All U.S. regions in this review require substantial annual capacity additions to meet the expected growth in demand. They range from a low estimate of about 550 MW/yr for the MAPP region to a high of 1100 MW/yr in ECAR followed closely by 1000 MW/yr for the southern California portion of WSCC. Opportunities therefore exist for Canadian utilities to meet, at least, part of the U.S. forecast capacity needs. (Figure #6)

- Even if Canada can capture 20% of the U.S. market, this will still be equivalent to an average of 200 MW/yr of long-term firm export sales into the California market, about 300 MW/yr into the combined New York, New England markets and about 100 MW/yr into the U.S. Midwest (Figure #6).

- In Canada, only Ontario and Québec require significant annual capacity additions (i.e. 600-700 MW/yr) to meet forecast domestic demands. This means that every three years, Ontario Hydro may be required to add two - 850 MW nuclear units or their equivalent to meet its increasing demand. Québec, on the other hand,

may be required to add every three years the equivalent of two-1000 MW hydro plants similar to Grande Baleine 1 to meet its anticipated increase in load growth (Figure #6).

- The annual capacity requirements in both BC and Alberta are relatively large enough for both provinces to install large hydro and thermal units (i.e. 400 MW sizes) and thereby obtain the benefits of economy of scale without carrying ordinately high generation reserve margins. The same is not true for Manitoba and Saskatchewan. In those provinces unit size additions of about 150 MW are about the maximum permissible without incurring high generation reserve margins and associated costs in order to ensure no degradation of the reliability and security of the electric power systems. (Figure #6)

- In the Maritime Provinces, only New Brunswick has and will continue to install large nuclear and thermal generating units (i.e. 630 MW Lepreau nuclear unit and 450 MW Belledune Coal fired unit). New Brunswick, is a special case because part of the output of the Lepreau #1 unit has been sold to US purchasers (i.e. 230 MW) on a "unit participation" basis. These contracts effectively reduce New Brunswick's share of the unit to about 400 MW. Also, New Brunswick has strong interties (i.e. 2400 MW) with large neighbouring systems (i.e. Québec and New England) as well as with Nova Scotia and Prince Edward Island. These interties thus allow NB access to about 2000 MW of capacity outside the province in cases of emergencies. (Figure #6)

6. REGIONAL COOPERATION AND DEVELOPMENT OPPORTUNITIES

Because of the geographic size of Canada and the US, there are technical and economic limits to electricity trade between the interconnected North American electric power systems. These technical trade barriers result from consideration of system network stability and security. As a result any practical consideration of cooperation and development opportunities between systems can only be made from a regional not national perspective.

Figure #7 shows the breakout of the Canadian and selected US systems into five natural regions within which the opportunities for trade appear to be practical if economic conditions exist to make it happen.

TABLE 2

Economic Ranking of the Various Types of Generation in Canada & U.S.

Approx. Economic Ranking	LUEC Range mill/kW.h	Generator Chs		Economic Chs.						Canada	USA
		Type	Lead Times (Yr)	Capital			Fuel			Provinces	States
				Low	Med	High	Low	Med	High		
1	33	sub bit Coal (low Sulf)	4-6.		x		x			Alt.	
2-10.	43-48.	hydro	6-8.			x	x			Nfld, Que Man, BC	None (most hydro dev.)
12-14.	50-55.	lignite Coal (low Sulf)	4-6.		x (+)		x (+)			BC, Sask	Midwest
16	50-65.	Nuclear	6-8.			x	x			Ont	None (no new orders since 1970's)
18-25	65-80.	bituminous Coal (med to high sulphur)	4-6.		x			x		Ont, NB NS	NY , NE ECAR
26-27	90-100.	combined cycle nat. gas	2-3.	x					x	Ont.	ECAR NY, NE, Calif.
28-29	110-150.	oil steam comb. cycle	3-4.		(-) X				x	Nfld, PEI	

TABLE 3

Nominal Levelized Unit Energy Cost (LUEC) at Market for Various Types of Generating Facilities in Canada and the U.S.A. for in service in the Year 2000 in mills/ KW.h (Can.)

A - CANADA

Province	Description	Gen. Type	MW Size	Nominal LUEC (mills/KW.h) 2000 $	Econ. Rank	LUEC (1) ratio
New Foundland & Labrador	Gull Island	Hydro	2264	39.2	2	1.22
	Muskrat Falls	Hydro	820	44.7	6	1.38
	Holyrood	Oil Steam	150	112.5	28	3.46
Nova Scotia	Sheet Harbour (NS)	Coal Steam	300	66.5	22	2.04
	Point Aconi	Coal Steam	150	68.4	23	2.10
	Sheet Harbour (Exp)	Coal Steam	300	90.6	25	2.78
P.E.I.	Maritime Electric	Oil C.C.	24	154.4	29	4.73
New Brunswick	Lepreau # 2	Nuclear	650	75.6	18	2.32
	Belledune	Coal Steam	450	69.6	21	2.14
	Grand Lake	Coal Fld. Bed	200	67.6	23	2.10
Quebec	Brisay	Hydro	460	43.1	3	1.33
	La Forge # 1	Hydro	820	44.8	7	1.38
	La Forge # 2	Hydro	318	46.4	9	1.43
	Grande Baleine # 1	Hydro	1000	48.1	10	1.48
	Sainte Marguerite	Hydro	822	49.5	13	1.52
	Eastmain # 1	Hydro	510	50.7	15	1.56
	Broadback # 1	Hydro	780	58.4	17	1.81
Ontario	Darlington B	Nuclear	881	48.7	11	1.51
	New Nuclear	Nuclear	881	55.1	16	1.69
	New Coal	Coal	740	70.7	20	2.17
	New Coal (IGCC)	Coal	600	70.5	19	2.16
	Hearn GS (Modified)	Nat. Gas	660	90.3	26	2.49
	New C.C.	Nat. Gas	660	92.5	27	2.84
Manitoba	Conawapa	Hydro	1300	44.5	4	1.37
	Wuskwatin	Hydro	350	44.7	5	1.38
Saskatchewan	Shand # 2	Lignite Steam	280	48.7	12	1.49
Alberta	Keephills # 3	Sub bit Steam	375	32.6	1	1.01
British Columbia	Peace Site "C"	Hydro	900	46.3	8	1.42
	Hat Creek	Lignite Steam	500	50.2	14	1.54

B- UNITED STATES

New York (2)	Sommerset	Coal Steam	682	76.6	25 (U.S.)	2.36
	New C.C.	Nat. Gas	390	93.5	26 (U.S.)	2.87
New England	New Coal	Coal Steam	700	80.1	25 (U.S.)	2.46
	New C.C.	Nat. Gas	390	101.5	28 (U.S.)	3.12
Mid West	Sherco # 4	Lignite Steam	500	55.8	16 (U.S.)	1.72
California	New C.C.	Nat. Gas	390	89.9	25 (U.S.)	2.76

(1) LUEC ratio = LUEC of Plant X

LUEC of most economic plant (i.e. Keephills)

(2) Assume ECAR costs similar to New York.

FIGURE 3

Nominal LUEC in mills/KW.h* for selected North American generating Facilitites for in service in the year 2000. Based on average generation for hydro, and base load for all other thermal plants (i.e. 80% CF).

*** Expressed in Canadian $ in the year 2000.**

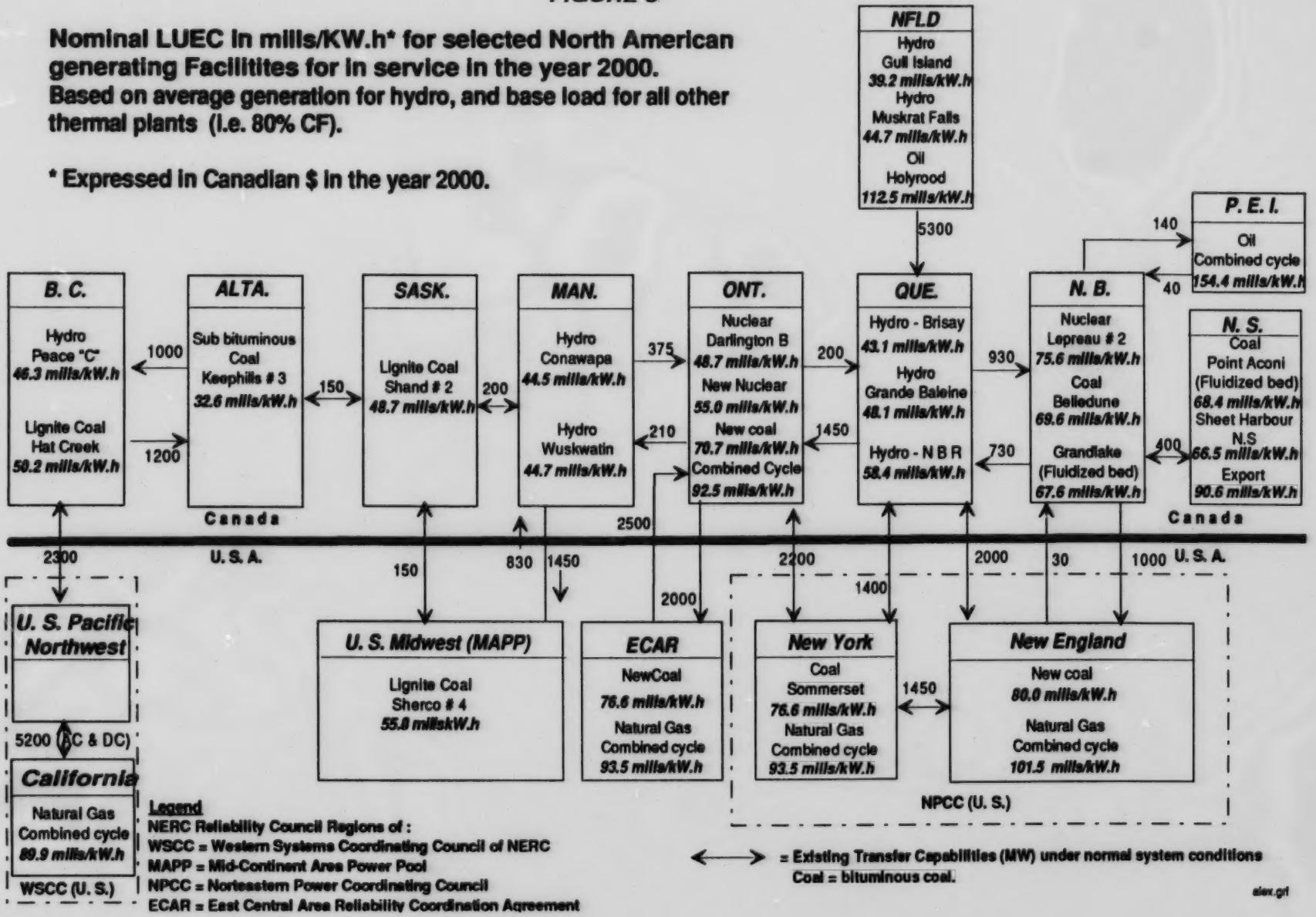
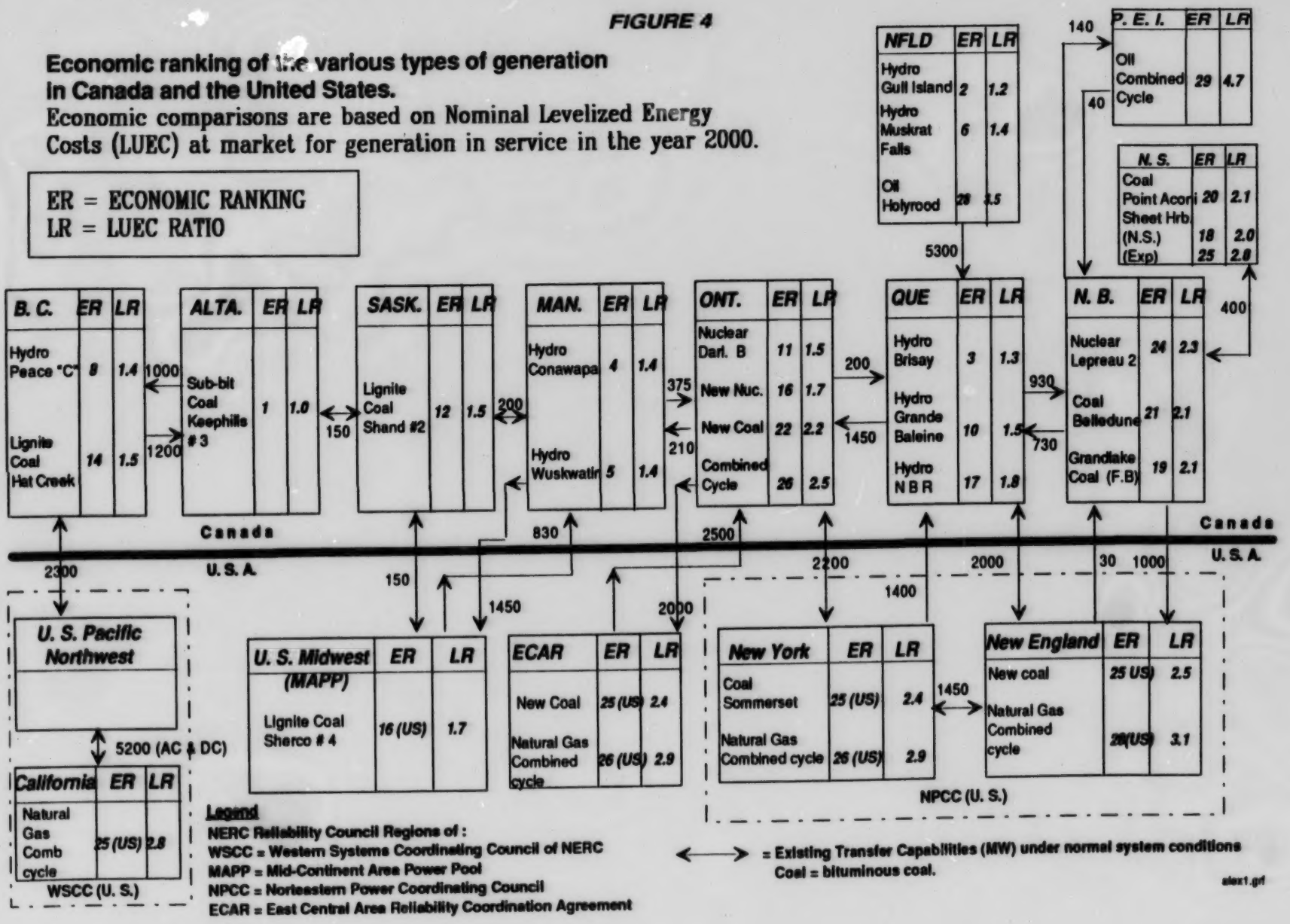


FIGURE 4

Economic ranking of the various types of generation in Canada and the United States.

Economic comparisons are based on Nominal Levelized Energy Costs (LUEC) at market for generation in service in the year 2000.

ER = ECONOMIC RANKING
LR = LUEC RATIO



Legend

NERC Reliability Council Regions of :
WSCC = Western Systems Coordinating Council of NERC
MAPP = Mid-Continent Area Power Pool
NPCC = Northeastern Power Coordinating Council
ECAR = East Central Area Reliability Coordination Agreement

<--> = Existing Transfer Capabilities (MW) under normal system conditions
Coal = bituminous coal.

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FIGURE 5

Nominal Fuel LUEC in mills/KW.h* for selected North American generating Facilitites for in service in the year 2000
Based on average generation for hydro, and base load for all other thermal plants (i.e. 80% CF).

*** Expressed in Canadian $ in the year 2000.**

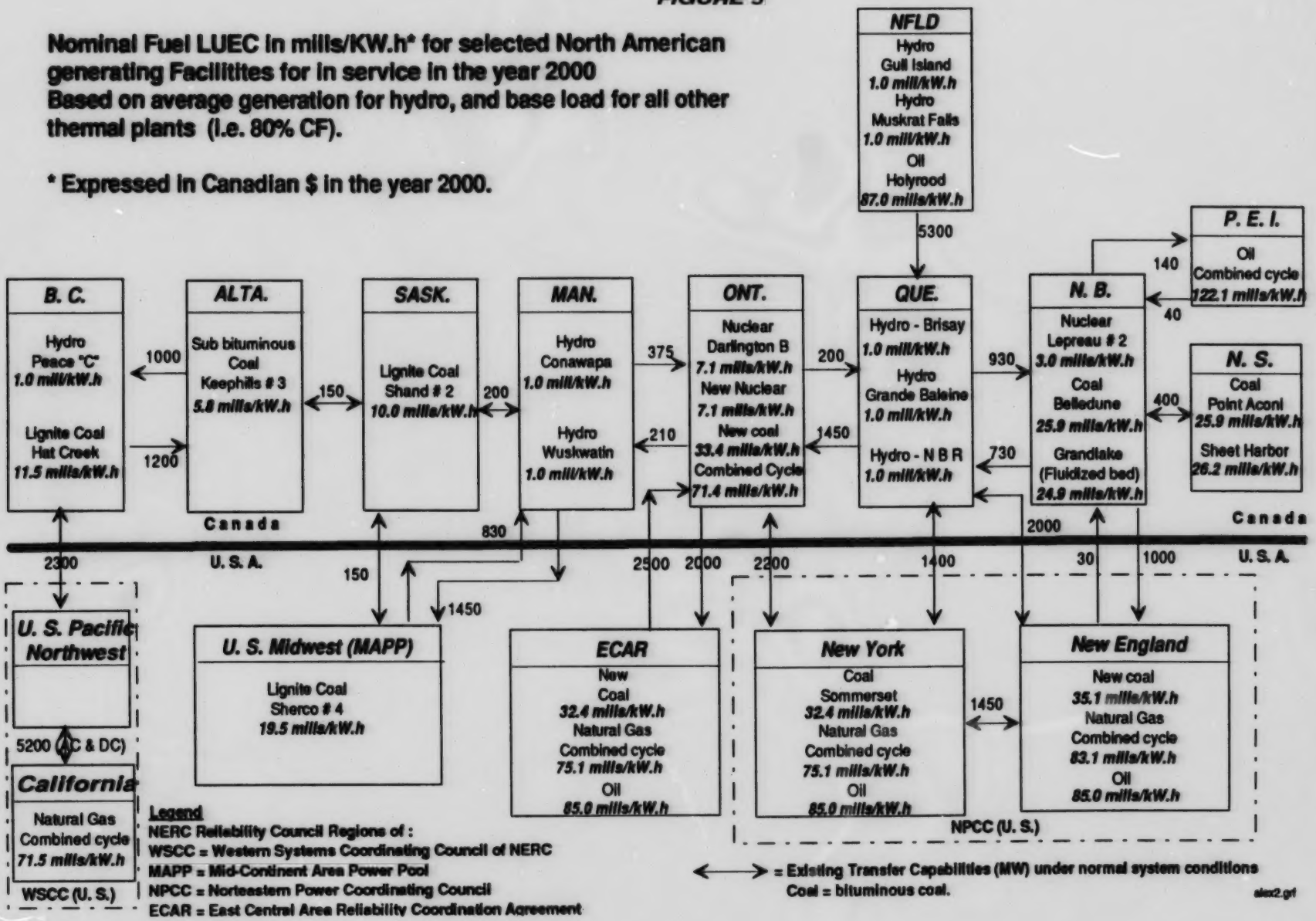
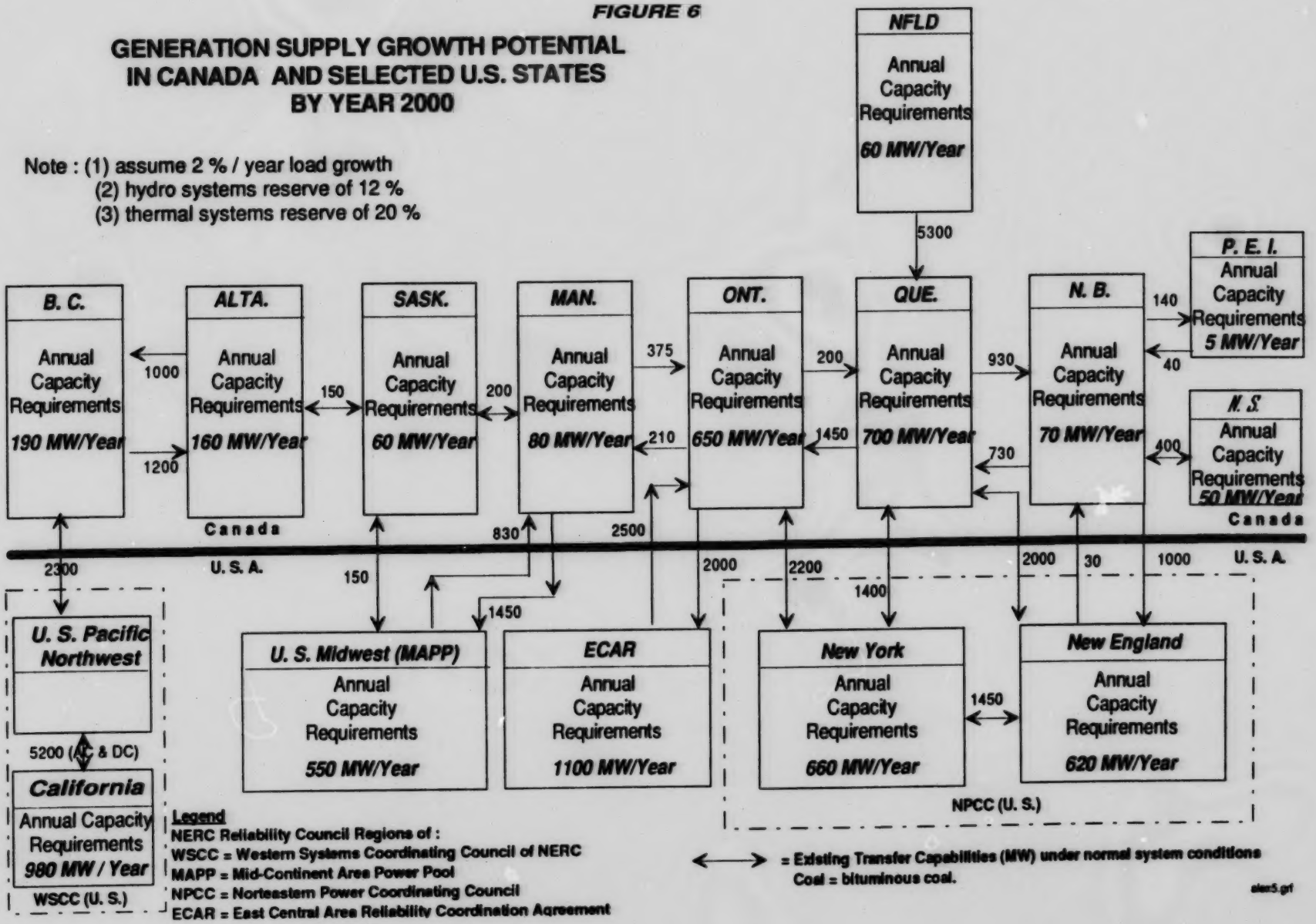


FIGURE 6

GENERATION SUPPLY GROWTH POTENTIAL IN CANADA AND SELECTED U.S. STATES BY YEAR 2000

Note : (1) assume 2 % / year load growth
(2) hydro systems reserve of 12 %
(3) thermal systems reserve of 20 %



The following sections deal with the cooperation and development opportunities within each of these regions.

6.1 Region #1: BC/Alberta/California

British Columbia, Alberta and the Pacific Northwest and Southwest, particularly California, form a natural development region. This region is part of the NERC Western Systems Coordinating Council (WSCC) which extends from the Pacific to the prairies (i.e. in Canada up the Alberta/Saskatchewan border). This region also forms part of the Western Interconnection and operates separately from the Eastern Interconnection which stretches from the prairies to the Atlantic.

Figure #8 shows the LUECs of the generating facilities, the associated ACRs for each province and the state of California as well as the existing interconnection transfer capacities between the systems. In this study we focused only on California as it appeared to be the most lucrative market for Canadian Electricity exports. It is recognized that there is also a growing market for electricity export into the Pacific Northwest. In addition Canadian opportunities in the California market may be hindered by competition from the Desert Southwest and Mountain regions of the U.S. Also shown in figure #8 is the interprovincial and international market potential for electricity trade within the region.

From Figure #8 the following observations can be made:

- Natural gas-fired generation costs in California are almost 3 times the cost of Alberta's sub-bituminous coal-fired generation. In addition, it is twice as costly when compared with B.C.'s Site "C" hydro generation. These margins may be somewhat reduced if other supply alternatives (e.g. coal-fired generation in B.C.) are utilized.

- Even adding the cost of transmission upgrades on the U.S. North South intertie to transport Canadian electricity to California, it appears that Canadian exports will be more competitive than U.S. alternative supplies in that market.

- If Alberta could access the California market, via the BC and Bonneville Power Authority (BPA) systems, it would offer that province a much more lucrative trade than dealing only with BC.

- Although Alberta's generation is 50% less costly than BC's, significant transmission upgrades between Alberta and BC will be required to bring the Alberta supply to the BC market. However, opportunities may exist for some form of coordinated development; BC Hydro and TransAlta (representing the utilities of the AIS) are now studying this potential.

- Alberta's predominantly thermal system with its low generation costs of 6 mills/kW.h provides significant low cost surplus energy which can be coordinated with the capacity available on the energy constrained BC Hydro system.

- Potential opportunities thus exist for hydro/thermal coordination of the combined provincial resources.

- Annual capacity requirements for the combined provinces of BC and Alberta are estimated to be about 350 MW/yr. This means that about a 1000 MW plant may be required every three years to meet the expected increase in demand. Opportunities therefore appear to exist for the coordination and planning of the generation programs in each province to serve the western Canadian region as a whole.

- Staggering of generation additions between the two provinces, reinforcing the interprovincial ties, etc through the joint planning of generation and transmission developments could provide significant benefits to both provinces. In addition, any potential capacity and energy surpluses that may result from such developments could be better marketed to maximize the revenues generated from export sales.

- Short term firm exports by BC Hydro with energy firmed-up by Alberta could enable higher valued exports to be made into the California market.

- The marginal generation in California is combined cycle generation using relatively high cost natural gas. This allows increased opportunities for short term economy energy exports by BC Hydro or by TransAlta via BC Hydro's network. (Both types of exports are now taking place as transmission access opportunities arise on the BPA North/South interties.)

- BC is proceeding with the formation of the POWEREX Pool Operation (PPO). PPO is a marketing operation that will serve short-term bulk electricity markets within and outside BC, including Alberta and the western United States. PPO will facilitate short-term electricity transactions to realize competitive opportunities and efficiency gains in the bulk power markets for the benefit of BC. Short-term transactions are any electricity transactions with a duration of less than one year.

- BC and Alberta are winter peaking systems and consequently have surplus capacity during the summer periods. The same is true for US Utilities in the Pacific Northwest. Utilities in California on the other hand are summer peaking systems with surplus capacity during the winter months. Potential opportunities therefore exist for summer/winter seasonal diversity exchanges between utilities in the Pacific Northwest including BC and Alberta and those in California. Even if US utilities in the Pacific Northwest have priority over Canadian utilities to such diversity trade, there still appears to be opportunities for BC and Alberta to take advantage of the potential remaining seasonal diversity trade.

- In lieu of seasonal diversity exchanges there might also be potential for long-term summer sales (i.e. from May to Oct.) by BC/Alberta utilities into the California market if Canadian utilities cannot be assured of capacity return from California during the winter periods.

- If BC and/or Alberta can capture 20% of the California market it will mean, on average, about 200 MW/yr of long-term firm exports.

- To capture such a high share of the US market, BC and Alberta would have to pool their resources. For example, a firm export sale to California of 1000 MW for a 30 year period would only satisfy that state's growing demand for one year.

FIGURE 7

REGIONAL COOPERATION AND DEVELOPMENT OPPORTUNITIES

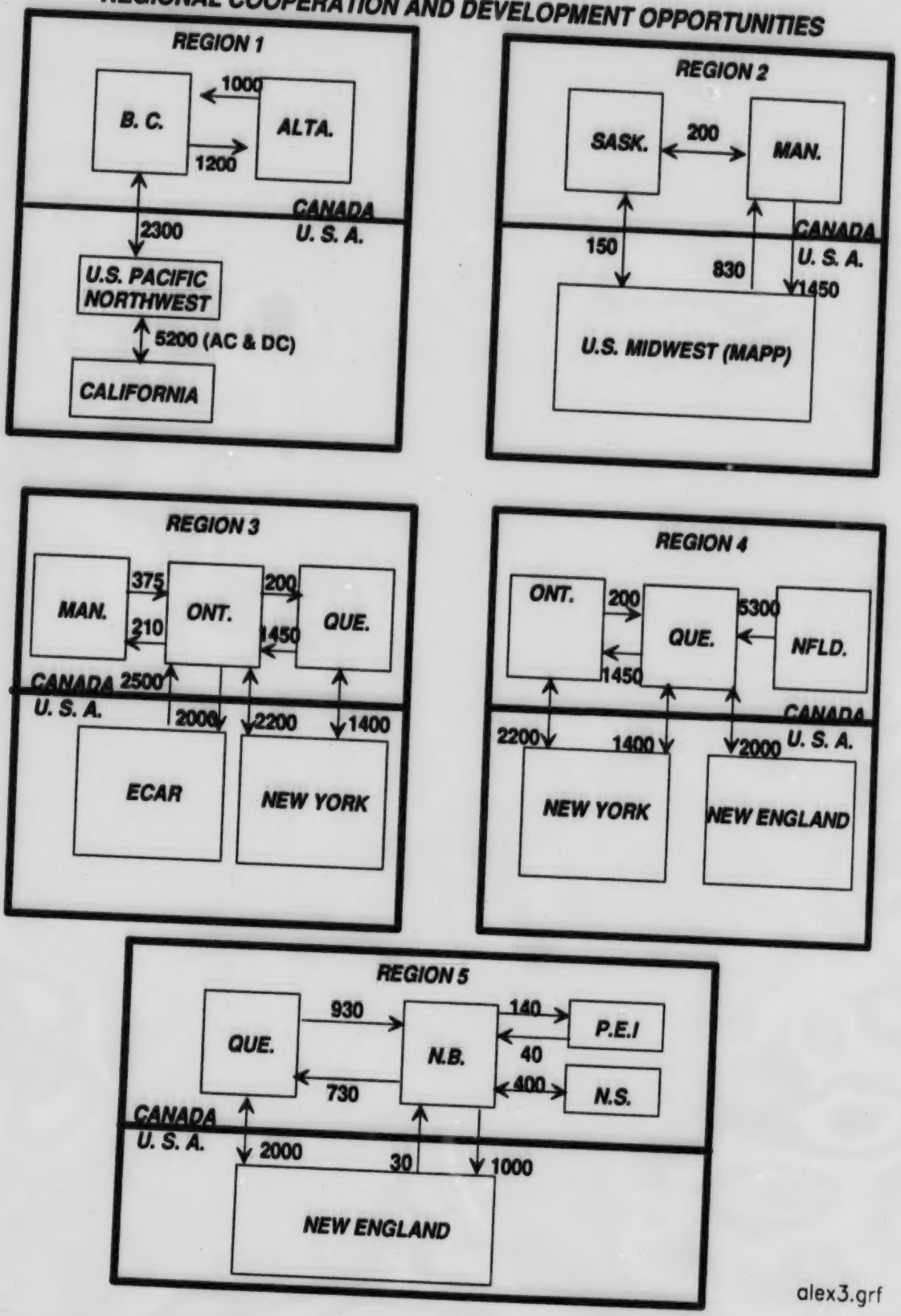


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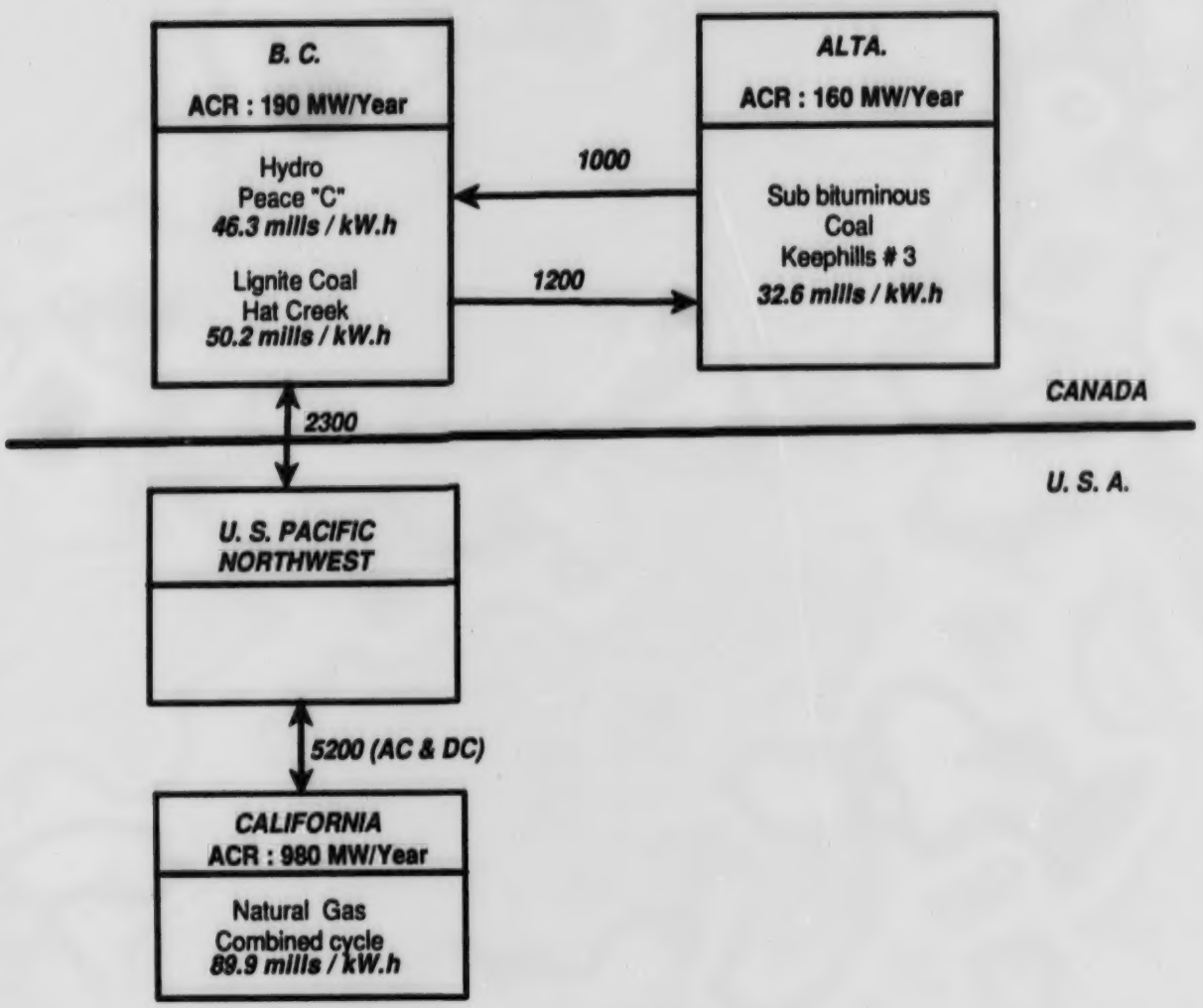
FIGURE 8
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR REGION 1
ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		LUEC mills / KW.h		Negotiating Margin
INTERPROVINCIAL	B. C.	ALT.	46	32	14 mills / kW.h
INTERNATIONAL	B.C.	CALIF	46	90	44 mills /kW.h
	ALT.	CALIF	32	90	58 mills / kW.h

A combination hydro/thermal export deal using BC's hydro and Alberta's thermal resources would provide both BC and Alberta with substantial benefits as well as shared risks.

- Barriers to increased international trade exist because the Bonneville Power Authority (BPA) Transmission Access Policy can restrict Canadian exports via BPA's North/South intertie from accessing the California market.

- We understand that BC and BPA are negotiating to provide BC with greater transmission access in return for certain concessions to BPA.

6.2 Region #2: Sask/Manitoba/US Midwest

Saskatchewan, Manitoba and tHe US Midwest form a natural development region. This region comprises the NERC Mid Continent Area Power Pool (MAPP) and is part of the Eastern Interconnection.

Figure #9 shows the cooperation and development opportunities for this region from which the following observations can be drawn:.

- As Saskatchewan's lignite generation costs are very similar to Manitoba's hydraulic generation costs, the opportunities for regional development in the two prairie provinces appear limited.

- Both provinces are geographically very large with low annual capacity requirements. Therefore any developments on a regional basis may require expensive long distance high capacity interties to reinforce the existing ties. These additional capital costs would create significant barriers to greater regional developments.

- However opportunities for joint planning may still exist which would allow for:

  (i) the staggering of generation in each province to serve the joint provincial demands more economically.

(ii) Greater generation reserve sharing to reduce the capacity margins required for planned and forced outages of generating facilities within the existing tie-line limits.

- Generating costs in Manitoba are estimated to be about 25% less than the best alternative (i.e. lignite plants) in the U.S. Midwest.

- This comparative advantage does not appear to be large enough to enable Manitoba to penetrate the U.S. Midwest market for the following reasons:

  (i) U.S. utilities may require at least a 20% (i.e. 8 mills/kW) price discount (i.e. this was the basis of the Manitoba Hydro - NSP 500 MW sale from Limestone G.S.)

  (ii) Additional intertie costs could absorb the remaining negotiating margin (i.e. 3-4 mills/kW.h).

- Manitoba was able to negotiate a 500 MW long-term firm sale from the output of Limestone G.S. with Northern States Power (NSP). However the cost of Limestone was less than Conawapa. It is therefore not surprising that Manitoba's negotiations with U.S. Midwest utilities are at a standstill.

- Manitoba is a winter peaking system while some U.S. Midwest utilities are summer peaking systems. Thus opportunities for summer/winter diversity exchanges do exist. In fact Manitoba now has 300 MW of diversity sales with NSP and is negotiating to increase that amount to 500-700 MW starting in the mid 1990's.

- In parallel with negotiations with the U.S., Manitoba has been negotiating with Ontario Hydro and has recently signed a 1000 MW long-term sale. The Conawapa plant would be committed to serve this load and is expected to come into service in the late 1990's.

- With this sale, it is unlikely that Manitoba would be interested in any further large long-term firm exports deals with utilities in the US Midwest or Canada.

- Joint hydro/thermal coordination opportunities exist which would allow Manitoba to firm-up its capacity by accessing Saskatchewan's thermal energy surpluses. Such opportunities may be limited however because of the availability of surplus energy from Saskatchewan and the uncertainty of any ensuing economic benefits.

- On the other hand, Manitoba Hydro and Northern States Power have concluded an energy agreement which allows Manitoba to call on up to 1500 GW.h in any 12 month period to firm-up its dependable capacity supply when stream flows are low or critical.

- The 1500 MW international tie capability between Manitoba and the U.S. Midwest is not only large enough to transmit all firm capacity export commitments but also to make interruptible energy sales when opportunities exist. The marginal fuel costs in the U.S. Midwest provides significant economic incentives for Manitoba to sell any surplus hydro it has available.

- During low water years this high capacity international tie also enables Manitoba to import electricity (i.e. in 1987-88) to meet its domestic demands.

- In summary Manitoba appears to have done a commendable job to increase its interprovincial and international electricity trade and continues to seek opportunities to further augment that trade.

6.3 Region #3: Manitoba/Ontario/Québec/New York/ECAR

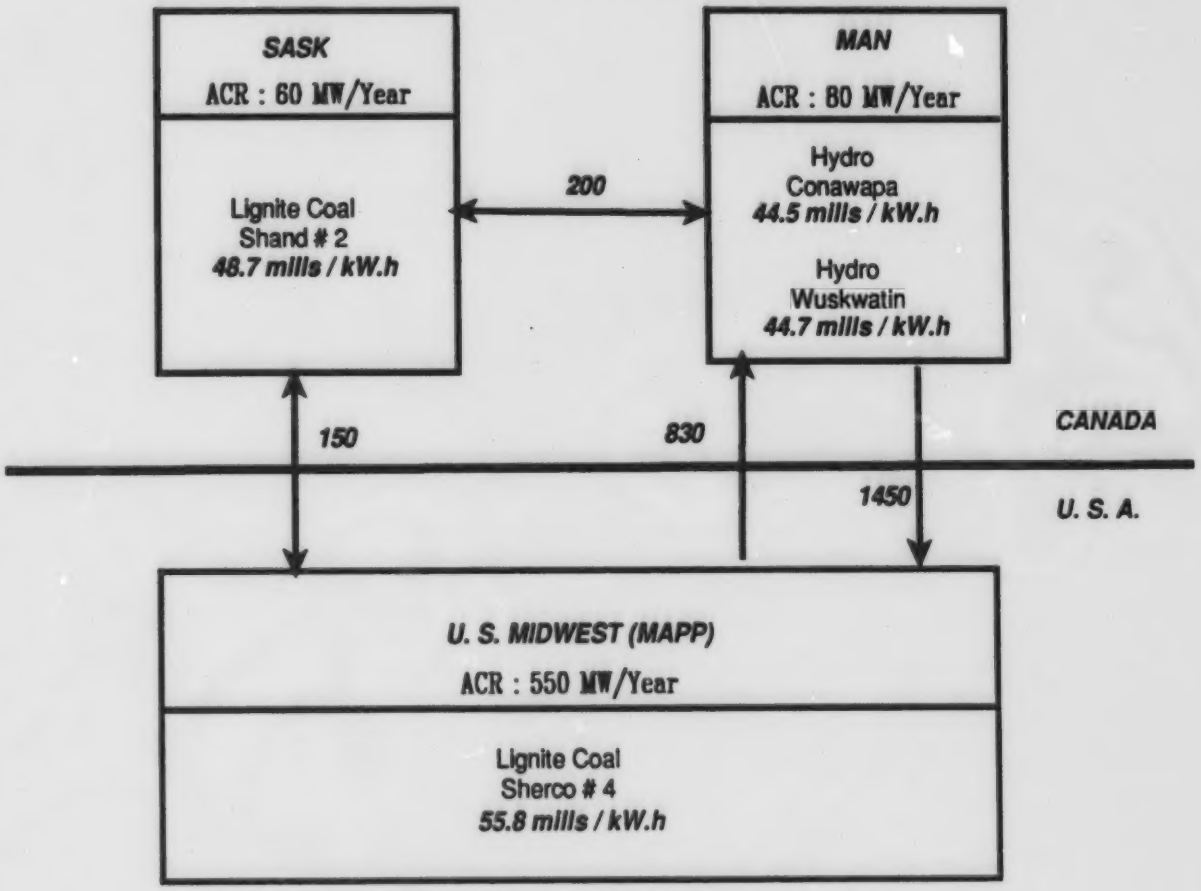
Although Ontario, Québec, New York and Michigan form a natural development region, the recently concluded 1000 MW long-term purchase/sale agreement between Ontario and Manitoba now also places that province within this region. This region comprises part of the NERC MAPP, the Northeast Power Coordinating Council (NPCC) and the East Central Area Reliability Coordination Agreement (ECAR).

Figure #10 shows the cooperation and the development opportunities for this region. From an examination of Figure #10, the following observations can be made.

FIGURE 9

COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR REGION 2

ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		LUEC mills / KW.h		Negotiating Margin
INTERPROVINCIAL	MAN	SASK	45	49	4 mills / kW.h
INTERNATIONAL	MAN	U.S. MIDWEST	45	56	11 mills / kW.h
	SASK	U.S. MIDWEST	49	56	7 mills / kW.h

- Ontario's best long-term economic alternative, by far, appears to be nuclear generation. It is about 30-40% cheaper than the comparable costs of new coal fired generation and decidedly more economic than combined cycle generation in the province using natural gas. It is recognized that the planning period for the nuclear plants is currently estimated to be about 15 years so that the earliest in-service date for such plants would be about 2005 and not 2000 (which was assumed in this study). Nevertheless because of the comparative nature of this analysis, the calculated benefits are not expected to significantly change with changes in in-service dates.

- Base load hydro generation costs in Manitoba are similar to Ontario's nuclear power costs from the Darlington B nuclear power plant and only marginally cheaper than new nuclear units in Ontario. It thus appears that considerations other than "pure" economics played a large role in the recent 1000 MW purchase/sale agreement between Ontario and Manitoba. These considerations, including secondary economic effects, were:

  (i) Increased diversity of supply for Ontario.

  (ii) Greater support and increased reliability for loads in northwest Ontario.

  (iii) Ontario's need to reinforce its ties between the northwest and central systems by the early 2000's. It was thus possible with only an additional transmission outlay of between $80-100 million to also increase its interprovincial ties with Manitoba from 375 MW to 1500 MW in order to support the 1000 MW Conawapa purchase.

  (iv) The reinforced interprovincial ties will also allow Manitoba hydro surplus energy, over and above the contract amounts, to penetrate the more lucrative southern Ontario market where Ontario's long-term marginal cost of generation using coal is estimated to be 33 mills/kW.h as opposed to the U.S. Midwest market where the comparable costs are about 19 mills/kW.h. Any economic benefits from such interprovincial trade would be shared between the two provinces.

- The Manitoba-Ontario agreement thus is a classical example of the cooperation that is possible between provinces to promote greater interprovincial electricity trade.

- Because Ontario's nuclear generation costs are estimated to be comparable to the costs of Québec's potential hydraulic generation at Grande Baleine and Nottaway Broadback Rupert, there appears to be little opportunity for large long-term firm purchase and sales agreements which would increase interprovincial electricity trade between the two provinces. Negotiations did take place in the 1987-89 period but have since broken off, generally because the price offered by Québec was more than Ontario was prepared to pay.

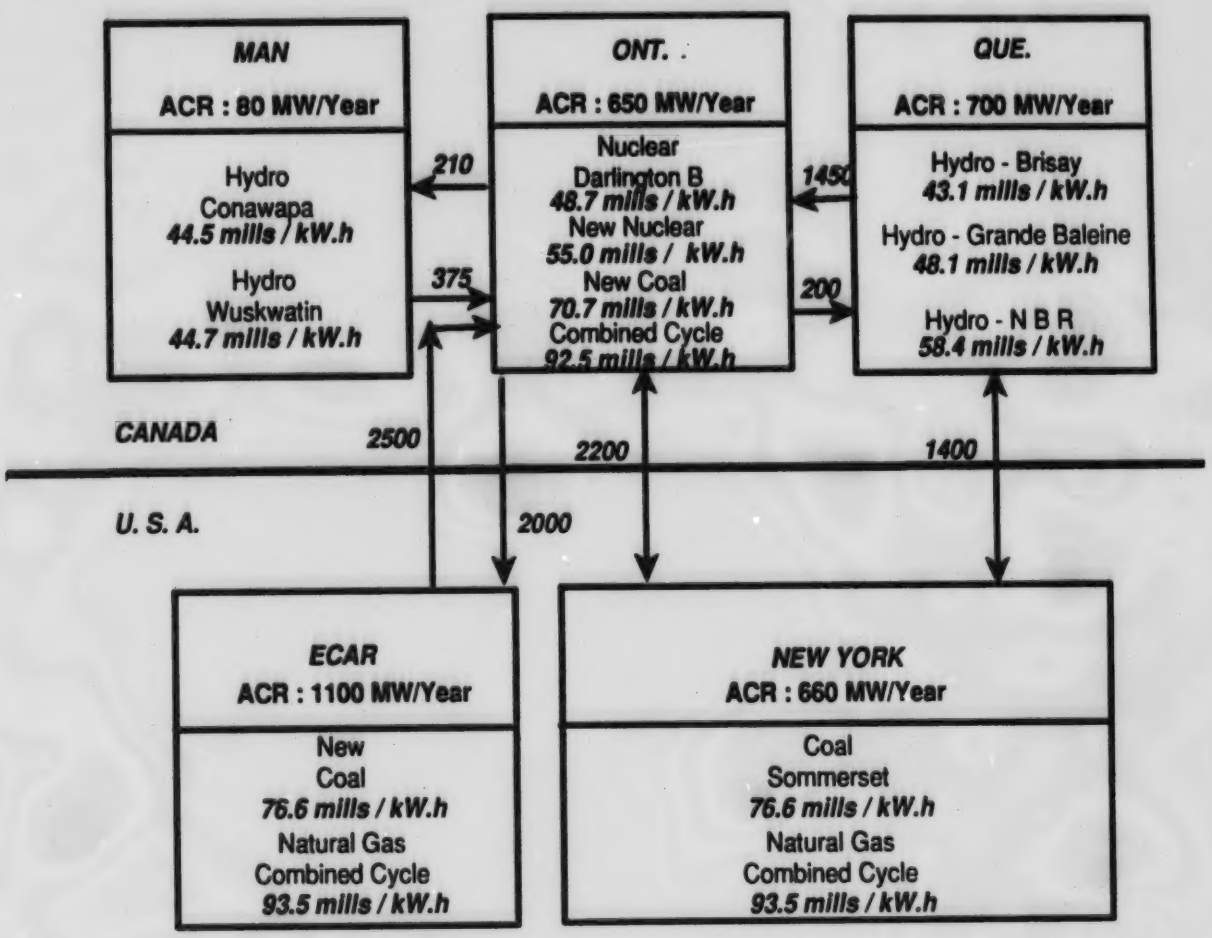
- At present the main Ontario and Québec systems are electrically separated. Electricity transfers are now only possible by physically isolating Québec generation and connecting it to the Ontario network and vice versa. This arrangement allows some 1450 MW of Québec generation to be transferred to Ontario, but only 200 MW of Ontario generation to be isolated for Québec's needs.

- Québec had significant hydraulic surpluses for many years. Ontario thus was able to access this energy with minimum additional capital expense to its transmission system by using the network arrangements described above.

- This situation has now changed. Québec's hydraulic surpluses are coming to an end, while Ontario, if it continues to build base load nuclear generation, may have significant amounts of relatively low cost nuclear energy (i.e. 7-8 mills/kW.h) during off peak periods of the day.

- There thus appear to be "energy banking" opportunities similar to arrangements that now exist between Québec and the New England Power Pool (NEPOOL). Energy banking allows lower cost U.S. electricity to be imported by Québec during off peak periods, stored in Québec's vast hydraulic reservoirs and be exported or "returned" during peak periods when NEPOOL's marginal cost of generation is high.

FIGURE 10
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR REGION 3
ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		LUEC mills / kW.h		Negotiating Margin
INTERPROVINCIAL	ONT.	MAN	55	45	10 mills / kW.h
	ONT.	QUE	55	48	7 mills / kW.h
INTERNATIONAL	ONT.	NY	55	77	22 mills / kW.h
	QUE.	NY	48	77	29 mills / kW.h

- Energy banking between Ontario and Québec, however, will require the two systems to be electrically connected, via high capacity direct current links in this case, to enable large transfers of electricity to take place in both directions.

- Strengthening the Ontario-Québec interprovincial ties will also allow a wide spectrum of other types of transactions to take place for mutual economic and reliability benefits. We understand that the two utilities are examining this possibility.

- Because Ontario and Québec are winter peaking systems while ECAR and New York are summer peaking systems, opportunities exist for both winter/summer seasonal diversity exchanges as well as summer sales. At present Québec has an 800 MW long-term seasonal diversity exchange with the New York Power Authority, however additional potential trade of these types may be possible.

- Although both Ontario and Québec have a decidedly economic cost advantage over generation in the State of New York, Ontario's stated policy is not to build for exports, unlike Québec which supports and encourages the advancement of its generation program for export purposes.

- It is clear that New York State is a lucrative market for Québec. For example the NEB's recently approved 1000 MW export sale by Hydro-Québec to the New York Power Authority (NYPA) is indicative of Québec's success in penetrating that market.

- The long-term export price of 65 mills/kW.h provides Québec with significant net benefits (i.e. benefit = 65-48= 17 mills/kW.h). It also provides NYPA with considerable net savings. (net savings 77-65 = 12 mills/kW.h).

6.4 Region #4: Ont/Québec/Nfld/NY/NE

Ontario, Québec, Newfoundland & Labrador, New York and the New England states form a natural development region. All these provinces and states except Newfoundland and Labrador are part of the NERC NPCC region.

Figure #11 shows the cooperation and development opportunities for this region. Examination of Figure #11 shows that:

- New England is an attractive market for Québec. Québec has negotiated a 500 MW firm export sale to the Vermont Joint Owners (VJO) and anticipates to negotiate with either NY and/or NE for up to another 2000 MW of long-term sales over the next few years for deliveries to commence in the late 1990's to early 2000's.

- The potential hydraulic development of Gull Island in Labrador appears to be the most economic hydro generation in Canada at 39 mills/kW.h. Muskrat Falls at 45 mills/kW.h is also very high on the economic ranking order of Canadian generation.

- The comparable cost of oil-fired generation on the Island is estimated at 112 mills/kW.h. This provides a powerful incentive for the exploitation of the Labrador hydraulic resources to serve the Island's increasing demands.

- The capacity of Gull Island at 2200 MW and Muskrat Falls at 820 MW gives a combined output for the two plants of 3100 MW. This capacity is too large for Newfoundland to readily absorb on its own system as the total domestic demand, even by the year 2000, is not expected to reach 2500 MW while the annual capacity requirements are not estimated to exceed 60 MW/yr.

- These potential hydro developments which are located in Labrador must be transmitted to the Island via an undersea HVDC high capacity cable through the Straits of Belle Isle.

- A potential fast track development of Gull Island and Muskrat Falls might be, in addition to serving the Island via a HVDC link, to consider long-term firm sales with systems large enough to absorb the full output of these plants. These markets are Québec, Ontario, NY State and/or New England.

- It should be noted that the LUECs for the various supply sources also include transmission costs to bring the supply to the market. In the case of Nfld's generation costs, they include the incorporation of an HVDC link which is

required to transmit the power from Labrador to the Island's load centre at St John's. The costs of Gull Island to serve either the Ontario, Québec or the NY and NE markets probably will be some what lower than the costs to serve the Island since the respective costs of transmission to serve each of these external markets are likely to be lower than the cost of the HVDC link to the Island.

- There appear to be very limited opportunities to conclude a long-term sale/purchase agreement between Québec and Nfld as the negotiating margin appears to be quite small.

- However like the Ontario/Manitoba case, Québec may find it more advantageous to reach a deal to purchase all or part of the output of Gull Island rather than to build. Some reasons for choosing this option include:

  (i) Need for more generation to support the Québec east system.

  (ii) Diversity of supply.

  (iii) Faster completion for Gull Island as opposed to Grande Baleine to serve Québec's increasing demand.

- We understand that negotiations between Québec and Nfld are continuing.

- Negotiating margins between Nfld and Ontario appear to be respectable. At one time there was considerable interest in a three party deal which would include Ont, Que. and Nfld. However, this has fallen through because Québec had indicated that it was interested in the full output of the plants in Labrador.

- Obviously the negotiating margins between Nfld and NY and/or NE provide a very lucrative market for Gull Island and Muskrat Falls even considering all the cost of added transmission which would be needed to supply the NY or NE markets.

- Exploiting Labrador resources for export purposes however raises a host of major considerations. These include:

  (i) Transmission Access through the Québec network to reach NY or NE.

  (ii) Potential loss sales for Québec that may result from a Nfld-NY or Nlfd-NE deal.

  (iii) Fed/Provincial jurisdiction.

- Even considering these formidable barriers it might be possible for Québec and Newfoundland to reach an agreement. Such an agreement might include the building of Gull Island and/or Muskrat Falls to serve Newfoundland, part of Québec's future requirements as well as the export market. A combined deal would provide Nfld with increased economic benefits through displacement of high cost oil fired generation on the Island and export sales, while at the same time provide Québec with capacity purchases at prices which are competitive with Québec's best alternative.

6.5 Region #5: Québec/NB/PEI/NS/NE

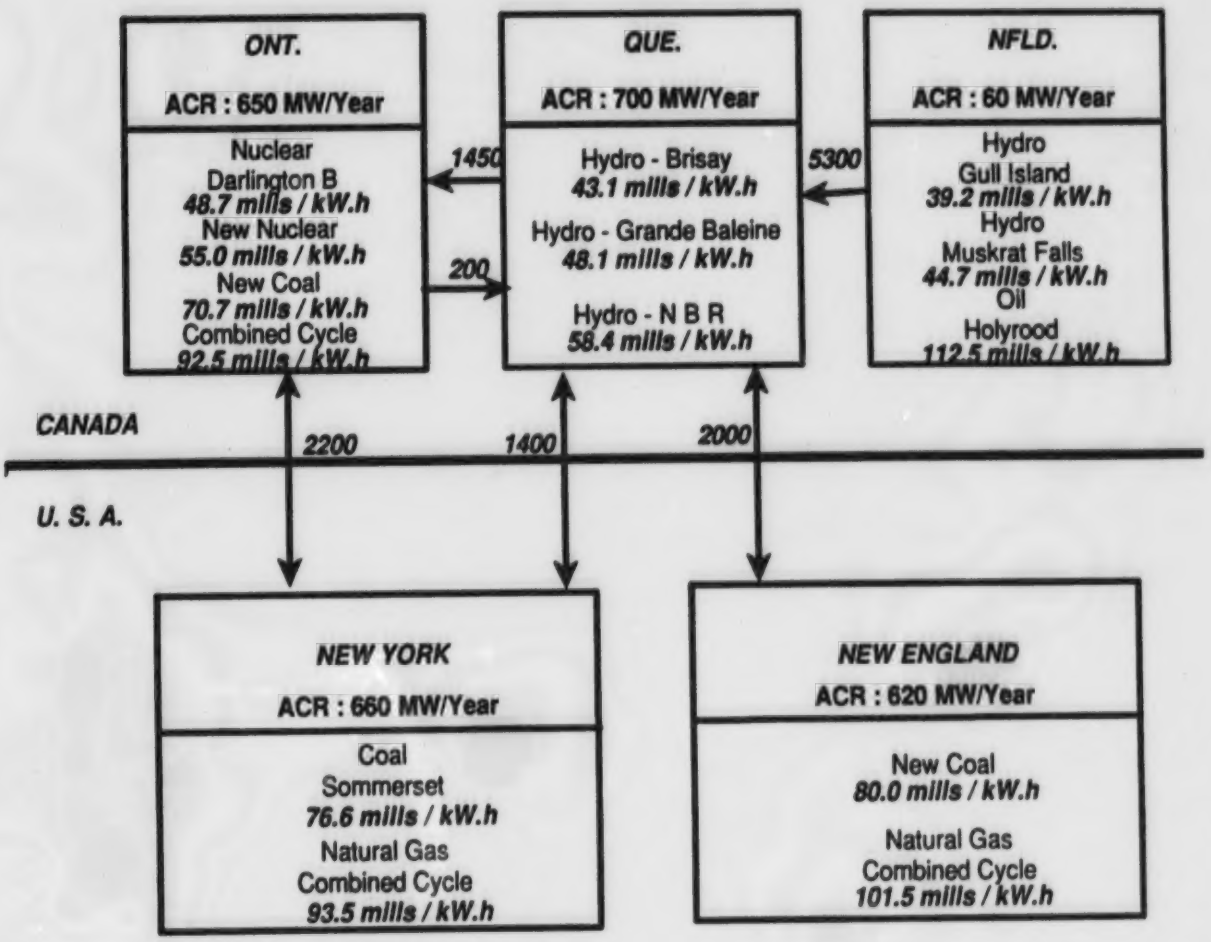
Québec, New Brunswick, Prince Edward Island, Nova Scotia and the New England states form a natural development region. All these provinces and states, except PEI are members of the NPCC region. Although Newfoundland could also be included in this region we have confined it to region #4 because from a historical perspective, Newfoundland has traditionally dealt with utilities in that region.

Figure #12 shows the cooperation and development opportunities for this region from which the following observations may be drawn.

- NB is strategically located geographically. It has direct ties to all other systems in the region.

- Both NS and PEI can only gain access to the Québec or New England markets by an overland route through NB or via undersea cables.

FIGURE 11
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR REGION 4
ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		LUEC mills / kW.h		Negotiating Margin
INTERPROVINCIAL	QUE	NFLD	48	39	9 mills / kW.h
	ONT	NFLD	55	39	16 mills / kW.h
INTERNATIONAL	NFLD	NY	39	77	38 mills / kW.h
	QUE	NY	48	77	29 mills / kW.h
	QUE	NE	48	80	32 mills / kW.h

- The interprovincial transmission between Québec and New Brunswick rated at 900 MW, allows New Brunswick to access hydraulic surplus energy from Québec to displace NB's higher cost oil and coal fired generation thus providing mutual economic benefits to both provinces. In fact, NB and Québec have conducted such trade for many years.

- Québec has recently decided that it needed additional peaking capacity, in the period starting 1991, to support, in particular, its loads in the Gaspe region.

- Instead of building in-province peaking capacity, Québec has recently concluded a long-term 20 year purchase agreement with New Brunswick starting in 1991. The agreement calls for a total of 400 MW to be made available by advancing the installation of combustion turbines in its system.

- The existing ties are sufficiently strong in the east to west direction (i.e. 700 MW) to support these purchases without new transmission.

- This is another good example of the cooperation possible between provinces to promote greater interprovincial joint developments and to enhance electricity trade.

- NB's ties to Prince Edward Island are rated at 200 MW. However, the transfer capability is limited to about 140 MW because the PEI peak load is only about 140 MW. These transfers have historically enabled PEI to purchase not only long-term firm capacity (i.e. 20 MW from the Dalhousie G.S.) but also to make other capacity and economy energy purchases to displace the Island's very high incremental cost of generation. In fact, total purchases from New Brunswick have traditionally provided 85-95% of the Island's electricity needs. This situation is expected to continue in the future.

- Although about 400 MW of interconnection capacity exists between NB and NS, there have not been any long-term firm purchase/sale agreements between the two provinces. In general, utility trade has been of an economy energy nature ranging between 200 to 650 GWh/year for the period 1984 to 1988. Such trade traditionally has not been large for the following reasons:

(i) Both NB's and NS's generation at the margin is either oil or coal. As a result, interchange opportunities appear limited.

(ii) When available, Québec surpluses were used first by NB to displace its own high cost generation leaving any remainder for additional trade with NS.

- The prospect of diminished Québec energy surplus in the future may create more opportunities for the NB-NS electricity trade.

- Because NB's hydro plants have limited storage, considerable surplus off-peak energy exists during the spring freshet months of the year. During those periods, Nova Scotia has purchased surplus hydraulic energy to displace its more costly fossil fired generation. Such trade is expected to continue in the future.

- New England has and continues to be an important export market for NB for both long-term firm power sales (i.e. participation in the Coleson Cove oil-fired and Lepreau #1 nuclear powered plants) as well as for short term sales of economy and other types of electricity exports pursuant to its several contracts and interconnection agreements with electric utilities in New England.

- On several occasions NB has stated that its purchases and sales with neighbouring utilities have allowed it to lower its domestic electricity prices to its ratepayers by about 10-15%. This is indicative of the importance that NB places on continued electricity trade with both its neighbouring Canadian and U.S. utilities.

- Comparing the cost of NB's coal-fired generation with Québec's hydro plants indicates limited opportunities for large long-term firm deals as the negotiating margins although respectable are not large.

- Negotiating margins between NB and PEI are large. Utilities in both provinces have just concluded a three year agreement starting November 1st, 1991 for the sale of 20 MW out of the Lepreau #1 plant.

- The long-run cost of the most economic unit in Maritimes (i.e. Sheet Harbour) has been estimated at 66 mills/kW.h.

- To help reduce electricity costs in the Maritimes, the Maritime provinces may benefit from the joint planning and development of their generating and transmission facilities through the formation of a tight pool. (i.e. Maritime Power Pool).

- In the mid to late 1970's the Maritime utilities undertook extensive studies on the feasibility of creating a Maritime Energy Corporation (MEC) with Lepreau #1 designated as a pool unit. MEC's mandate would include both capacity planning on a regional basis and the coordination of systems operation as a single operating entity. However for a number of reasons, both political and technical, the MEC was never formed.

- Such a pool could have a combined generation supply of 7000 MW by 2000. It would be only slightly smaller than Alberta's supply of about 8000 MW in the same time period.

- The Maritime utilities are presently investigating if there are any significant further savings available to the region if they were to do their planning on the basis that provincial boundaries did not exist. The utilities are expecting to report back on any such benefits by the end of 1991.

- Negotiating margins between Québec and PEI are even larger than those between New Brunswick and PEI. However transmission access and the cost of wheeling Québec's power through NB to PEI could create barriers to such trade. From Québec's viewpoint any sales to PEI will be very small in comparison to their other out of province sales.

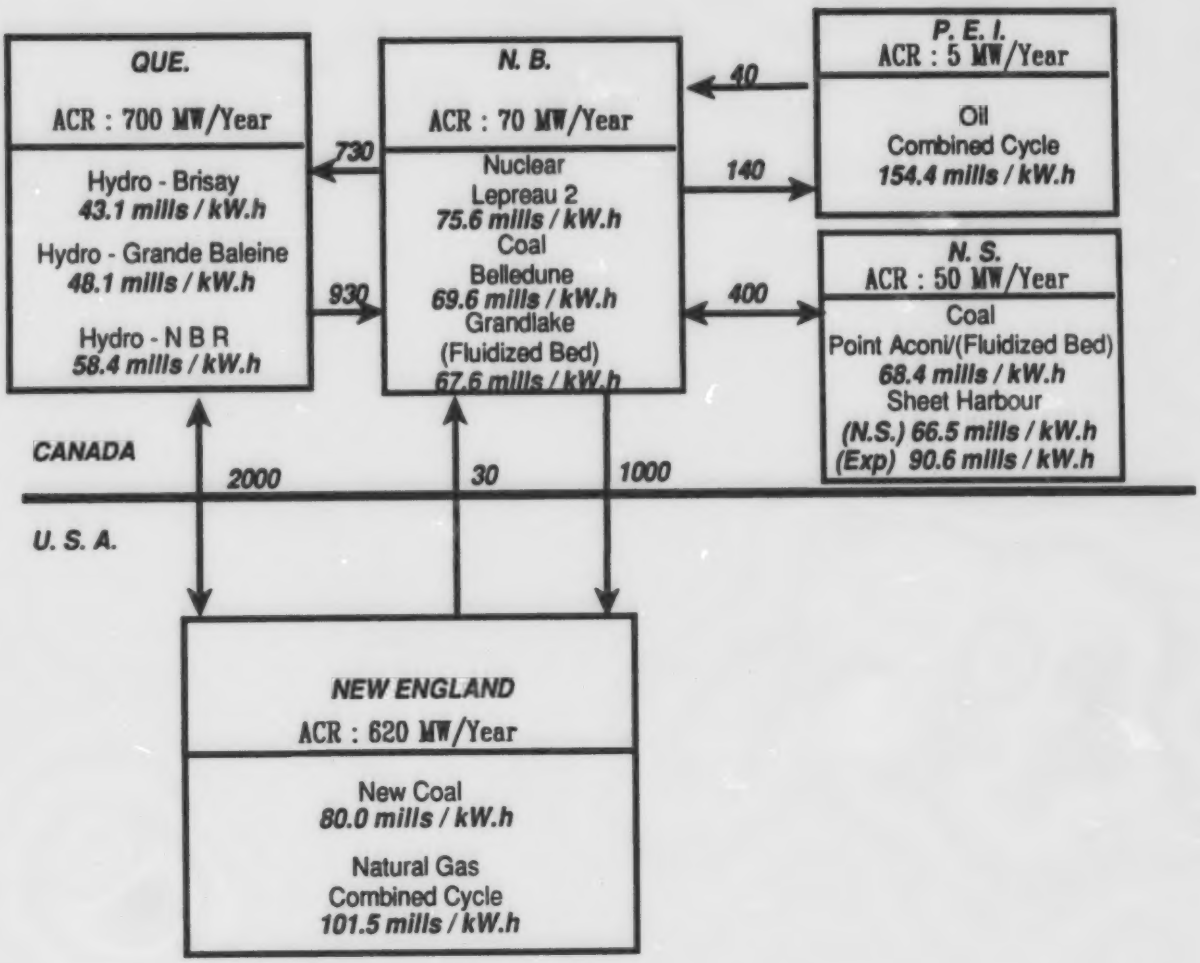
- Although the negotiating margins between Québec and NS are respectable, the transmission access through NB would have to be secured before any deals are realized.

- NB has over the years focused on the export market for increased trade opportunities. However the negotiating margins between new coal fired units in

FIGURE 12

COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR REGION 5

ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		LUEC mills / kW.h		Negotiating Margin
INTERPROVINCIAL	NB	QUE	68	48	20 mills / kW.h
	NB	PEI	68	154	86 mills / kW.h
	QUE	NS	48	67	19 mills / kW.h
	QUE	PEI	48	154	106 mills / kW.h
INTERNATIONAL	NB	NE	68	80	12 mills / kW.h
	QUE	NE	48	80	32 mills / kW.h
	NS (Exp)	NE	91	80	9 mills / kW.h

NB and coal fired generation is New England are not very large. It confirms the difficulty NB is having in its current negotiations with several New England utilities for the export sale of 400-600 MW of long-term firm power. The only overriding factor, which favors such a deal, is that while NB can still build new large scale generating facilities, New England, for a whole host of regulatory and environmental reasons, apart from economics, may be unable to build large scale coal fired plants for in-service in the mid 1990's when supply deficits are expected to occur.

- Negotiating margins between NB and NE increase from 12 to 34 mills/kW.h if comparisons are made between coal fired generation in NB and combined cycle natural gas fired generation in NE.

- Québec is decidedly more competitive than New Brunswick in the New England market as its negotiating margins are double those of New Brunswick. It is therefore not surprising that Québec was able to conclude an agreement with Central Maine Power (CEMP) for the long-term export sale of 1000 MW. However this contract was never finalized as the Maine Public Service Board subsequently did not approve the contract.

- We understand that Québec and NE are continuing to negotiate a new contract. However based on Québec's current supply situation it is unlikely that any new export deal with NE would commence before the early 2000's.

- Possibilities may also exist for a Combined Québec/Maritime export deal with NE.

- Québec's generation is predominantly hydraulic and therefore subject to the vagaries of weather uncertainties such as low precipitation and snow etc. In addition the Québec system has historically not matched-up to the reliability of other North American systems within the NPCC, although significant expenditures have been allocated to improve this situation. It should be noted however, that Québec's system characteristics (i.e. long radial lines connecting its hydraulic generation to load centres) has made it difficult in the past for it to abide by the NPCC criteria. Generation in the Maritimes, on the other hand, is predominantly coal or nuclear with secure fuel supplies. The Maritime utilities

generally meet the reliability standards and criteria set by the NPCC and coupled with New Brunswick's strategic position between Québec and New England may offer opportunities for more reliable and higher valued firm exports to New England based on a combined Québec-Maritime supply source.

- Although not explicitly included in Region #5, Newfoundland could gain access to the Maritime market if it could obtain transmission access through Québec. Under such a scenario, the results indicate that the negotiating margins between Newfoundland and the Maritime provinces will not be too dissimilar to the comparative margins between Newfoundland and New England as identified in Region #4. The reason for the similarity is based on the premise that in both New England and the Maritime provinces the preferred supply alternatives are coal-fired generation with similar supply costs.

7. ASSESSMENT OF THE BENEFITS FROM REGIONAL COOPERATION AND DEVELOPMENT OPPORTUNITIES

Section #6 provided a qualitative review of the cooperation and development opportunities that may exist between utilities within the interconnected North American regions. Many types of opportunities exist, but it appears clear from this assessment that there are five major types of opportunities for increased interutility trade. These are:

- Sharing of generation reserves between systems.
- Firm seasonal diversity exchanges between Canadian winter peaking and the US summer peaking systems.
- Firm summer export by Canadian systems.
- Benefits arising from new interconnections between systems.
- Long-term firm trade (i.e. the Build or Purchase option).

Based on the observations provided in section # 6, this section attempts to assess the potential net benefits that could be realized from the types of trade opportunities referred to above.

This assessment was made by using simple engineering economic models as well as simplifying assumptions in order to calculate the magnitude and scope of the potential benefits from seasonal diversity, summer sales etc between the respective interconnected utilities within each region. The results of these analyses therefore should only be taken as providing a broad brush indication of the potential benefits that might exist through greater regional cooperation. In addition it should be noted that the potential opportunities and resulting benefits described in this section by no means cover the full range of all the opportunities that might be realizable.

Opportunities through greater interutility cooperation and developments, broken into the five categories described above, are detailed in the sections that follow.

7.1 Sharing of Generation Reserves

Interconnections between systems allow utilities to share the generation reserves that must be installed to provide reliable and secure electricity to customers, thereby reducing the total amount of reserves that would have been required. Such reductions in generation reserve requirements thus provide tangible economic benefits to the parties.

Most interconnected Canadian utilities have agreements which would allow them to share generation reserves. As these types of benefits are now being realized and will continue to be realized in the future, it was considered unnecessary to further deal with these matters in this report except as noted in the section dealing with benefits arising from new interconnections.

7.2 Seasonal Diversity Exchanges and Summer Sales

Canadian utilities are winter peaking systems and consequently have surplus capacity during the summer months. US utilities, on the other hand, are summer peaking systems with surplus capacity during the winter months. Potential opportunities thus exist for summer/winter seasonal diversity exchanges between Canadian and US utilities. Also in lieu of seasonal diversity trade, summer seasonal sales opportunities also exist for Canadian utilities in those cases where they cannot be assured or don't plan to rely on return capacity and energy in the winter period.

It should also be noted that long term firm summer sales require the selling utility not only to have assured surplus summer capacity but also assured annual energy above its own domestic needs and other firm commitments to support such transactions. Therefore, in general systems which are predominantly thermal based and energy rich have a greater opportunity to engage in these types of sales than do hydro based systems. Hydro systems' energy capabilities are weather dependant and therefore may be energy constrained. Firm summer sales are still possible but they tend to be negotiated on a year to year basis depending on the availability of surplus hydro energy.

The net benefits from seasonal diversity exchanges can be calculated as the difference between the generating facility capital deferments and the cost of the transmission facilities necessary to make exchanges.

The gross benefits from long-term summer sales, on the other hand were calculated as the savings from the displacement of the energy and the deferment of capacity on the purchaser's system. Cost on the other hand would comprise the seller's production costs and the cost of transmission facilities required for the trade.

Appendix 4 provides details of the potential benefits from both seasonal diversity exchanges and summer sales for the regions described in this report.

7.3 Benefits From New Interconnections

Significant potential benefits exist when new or additional interconnections between utilities are placed into service. These include the potential reduction in generation reserve margins, as well as opportunities for short-term economy energy trade and energy banking.

Additional interconnecions provide added opportunities for utilities to further reduce the total amount of reserve that would be required to provide reliable electric service. As noted above, such reductions provide tangible economic benefits to the interconnected parties.

Short-term economy energy trade allows interconnected utilities access to less expensive generation than what is currently available on their own system. Economy energy from the supplying system is used to displace energy that could otherwise be produced by the

receiving system, but at a higher incremental cost. This results in economic benefits to both parties.

Energy banking allows low cost off-peak generation from a predominantly thermal system to be stored by a interconnected predominantly hydro system during the off-peak hours of the day and to be later returned to the thermal systems during peak hour periods when its marginal cost of generation is high.

Appendix 5 provides details of the potential net benefits from new interconnection opportunities between utility systems on a regional basis.

7.4 Long-Term Firm Trade

The necessary assumptions and premises that are required for long-term firm trade between interconnected utilities have been fully outlined in section 2.2 of this report. In essence it is based on the premise that utilities must meet their forecast increase in customer demands by adding new supply capability, either through building generation themselves or through purchases from others if the economics are attractive enough.

The net benefits from such long-term firm trade can be calculated as the difference between the purchaser's and seller's generation costs subtracted from the cost of transmission facilities necessary to affect the transactions.

Appendix 6 provides details of the potential net benefits from long-term firm trade among the interconnected North American utilities.

7.5 Summary of Results

The results detailed in Appendix 4 to 6 have been summarized in Table # 4.

Table #4 provides, by region, a summary of the cooperative arrangements that potentially exist between interconnected Canadian systems as well as between Canadian and U.S. systems. Also shown are the net benefits that might be realized if these opportunities are exploited. Finally those opportunities that have already been realized are shown in order to provide some indication of the magnitude that remains to be exploited.

From Table #4 the following observations are noted.

- Even if US utilities in the Pacific Northwest and those in California take full advantage of seasonal diversity exchanges and/or summer sales that exist between them, there remains significant scope for winter/summer seasonal diversity (i.e. 500 MW) and summer sales (i.e. 1000 MW) between the combined BC/Alt. systems and California. These potential net benefits have been calculated at $1.5 and $2.7 billion respectively. Whether these transactions will ever be realized will depend upon securing transmission access through the BPA system.

- Opportunities also exist for major long-term firm sales to California. For example a 1000 MW joint BC/Alta development would provide significant net benefits to all parties concerned. Net benefits from such a proposal have been estimated at $2.8 billion.

- About 850 MW of potential winter/summer seasonal diversity exists between Sask/Manitoba and the utilities in the U.S. Midwest. Net benefits have been calculated at $5.5 billion. It should be noted however that at present both Saskatchewan and Manitoba have seasonal diversity arrangements with U.S. utilities (i.e. total of 400 MW). In addition Manitoba has entered into further diversity exchanges with Northern States Power (i.e. 500 MW). These arrangements will effectively exploit the full potential diversity exchange that exist in that region.

- The potential for seasonal diversity exchanges between Québec and New York has been estimated at 1400 MW with corresponding net benefits of about $10.5 billion. It should be noted that Québec and NYPA have an 800 MW diversity agreement and thus a large portion of this potential has already been exploited.

- The Province of Ontario does not have a policy to encourage exports of electricity, and in fact with respect to nuclear generation has imposed a moratorium in the fall of 1990 related to the construction of new nuclear plants, making export dedicated nuclear plants impractical at this time. Nevertheless, this analysis appears to show that long-term firm nuclear power exports from

Ontario to ECAR or New York could provide major benefits to the parties involved. Net benefits from a 1000 MW export could range from $1.5 to $3.2 billion depending on whether those exports would defer U.S. coal or natural gas fired generation at the market.

- The province of Québec does have a policy to encourage electricity exports. Net benefits from a long-term sale of 1000 MW has been estimated to range from $2.2 to $4.0 billion. To date Québec has made long-term firm contracts of 1000 MW to NYPA and 500 MW to Vermont Joint Owners.

- Manitoba and Ontario have negotiated a 1000 MW firm long-term sales/purchase agreement which would require the construction of the Conawapa hydro plant in Manitoba to support the sale.

- Although the maximum potential seasonal diversity (i.e. 2500 MW) and summer sales (i.e. 5000 MW) appear to exist between Ontario and utilities in ECAR, we expect transfers of these types of trade could be considerably lower. Ontario's generation at the margin is coal and because that province has stringent acid gas emissions criteria, these opportunities may not be fully exploited. In addition as ECAR is made up of many interconnected utilities the seasonal diversity opportunities may be difficult to realize. Furthermore scheduled maintenance of large generating units during the summer period also would reduce the potential for such trade. Finally, even if transmission facilities were built to support these transactions loop flows and other transmission bottlenecks may cause restrictions. As a result, the expected seasonal diversity and summer sales potential are estimated to be 500 MW and 1000 MW respectively. The corresponding net benefits have been calculated to be $3.2 and $2.7 billion respectively. It should be emphasized that these benefits are not additive.

- A new 1000 MW HVDC interconnection between Quebec and Ontario is estimated to provide net benefits of $0.6 billion arising from potential reductions in generation reserve requirements as well as from opportunities for economy energy trade and energy banking.

- Gull Island and Muskrat Falls appear to be among the lowest cost potential generation developments in Canada. A fast track exploitation of these facilities

which would supply the Island of Newfoundland with 950 MW of base load capacity, including 150 MW of recall power from Churchill Falls, and would provide Québec and New England with 1000 MW and 1200 MW of long-term firm purchases respectively could result in significant net benefits to the parties. The overall net benefits from such a development scheme could reach $13.2 billion.

- An alternate exploitation scenario for Gull Island and Muskrat Falls, whereby capacity surplus to Newfoundland's requirements is purchased by Quebec, yields net benefits that are estimated at $7.8 billion. A third scenario has Quebec purchasing only 1450 MW, with the remaining 750 MW purchased by New Brunswick and Nova Scotia to defer coal generation. Under these assumptions, the net benefits are estimated at $8.8 billion. Both these scenarios result in all the benefits remaining in Canada.

- Seasonal diversity exchanges of 150 MW and summer sale of 250 MW exist between New Brunswick and Utilities in New England with corresponding net benefits for each in the range of $1.0 billion. However because New England's winter and summer peak loads are so close in magnitude, it is uncertain whether these benefits can be are realized.

- Long-term firm sale of 50 MW by New Brunswick to Prince Edward Island could result in net benefits of $0.4 billion.

- New England requires about 600 MW of new capacity each year to meet its forecast increase in electricity demand. A combined New Brunswick - Nova Scotia long-term firm export option to NE of about 1200 MW could provide net benefits of approximately $2.3 billion. However, such deals may be difficult to realize because of the factors used by NE in their evaluation of projects. In particular, emission externalities make natural gas the fuel of choice and may override the benefits from purchases identified above. To date New Brunswick has negotiated up to 230 MW of firm exports from the Lepreau # 1 nuclear unit to utilities in New England.

8.0 CONCLUSIONS

Because Canadian utilities are interconnected both interprovincially and internationally it is not possible to assess the potential benefits from enhancement of interprovincial trade without consideration of the potential benefits that might exist from international trade in electricity. This assessment, which was based on a North American perspective, indicates that significant additional benefits are possible from the potential opportunities in interutility electricity trade that appear to exist. To realize these potential benefits however, may require utilities, with the support of the provinces/or states, to cooperate more fully in:

- integrated systems planning
- providing transmission access and wheeling.

TABLE 4
Summary of the Potential Net Benefits by Regions from Cooperation and Developments
All values in $ of 2000 using a real discount rate of 6%.

Region	Type of Trade	Systems	Characteristics	Amt. of Exchange MW	Potential Net Ben. $ billions	Trade Already Realised
# 1 BC/Alt/ California	Sharing of Generation Reserves	BC-Alta	Intertie Cap. 600-800 MW			yes
	Seasonal Diversity Exchanges	BC/Alt with California	Winter Peaking Summer Peaking for 30 years	500	$1.5	
	Summer Sales	BC/Alt to California	30 year 6 month/yr summer sale at 80% seasonal c.f.	1000	$2.7	
	Long Term Firm Sales	BC/Alt to California	30 year sale at 80% c.f.	1000	$2.8	
# 2 Sask/Man US Midwest	Seasonal Diversity Exchanges	Sask/Man. with US Midwest	Winter Peaking Summer Peaking for 30 years	850	$5.5	300 MW between Man. & Northern States Power and 100 MW between Sask and Basin Electric
	Long Term Firm Sales	Manitoba to North States Power				Man. export of 500 MW to North. States Power
# 3 MAN/ONT QUE/NY ECAR	Sharing of Generation Reserves	Ont-Que Ont-ECAR Ont-NY Que/NY	200 - 1450 MW 1000 - 2500 MW 3200 MW 1400 MW			Yes
	Seasonal Diversity Exchange	Ontario with ECAR Quebec with New York	Winter peaking Summer peaking Winter peaking Summer peaking	500 1440	$3.2 $10.5	800 MW between Que. and NYPA
	Summer Sales	Ont - ECAR	30 year 6 month/yr Sale at 80%	1000	$2.7	
	Long Term Firm Sales	Manitoba to Ontario				Manitoba 1000 MW sale to Ontario
		Ontario to ECAR	30 Year Long Term Sale	1000	$1.5 - 3.2	
		Quebec to NY	30 Year Long Term Sale	1000	$2.2 - 4.0	Quebec has neg. a 1000MW export to NYPA and a 500 MW export to Vermont.

TABLE 4 (con't)
Summary of the Potential Net Benefits by Regions from Cooperation and Joint Developments
All values in $ of 2000 using a real discount rate of 6%.

Region	Type of Trade	Systems	Characteristics	Amt. of Exchange MW	Potential Net Ben. $ billions	Trade Already Realised
# 4 Ont/Que/ Nfld/NY/NE	New Interconnection	Ont - Que	Res. sharing Econonomy Trans Energy Banking	200 MW 3000 GWh/yr 450 GWh/yr	$0.6	
	Exploitation of Gull Island & Muskrat Complex in Lab	Newfound. Total	To back off Isld thermal generation & defer Isld gen.	800 MW 150 MW (recall) 950 MW	$4.5	
		Quebec	To defer Hydro Gen. in Quebec	1000 - 2200 MW	$1.5 - $3.3	
		NB and NS	to defer coal gen. in NB and NS	0-750 MW	$0 - $2.1	
		N. England	To defer coal and/ or Nat. Gas fired gen. in N. England	0 - 1200 MW	$0 - $7.2	
		TOTAL BENEFIT :			$7.8 - $13.2	
	Long Term Firm Sales	Nfld to Quebec				Nfld sale of 5200MW from Churchill Falls G.S. to Quebec
# 5 Que/NB/PEI/ NS/NE	Sharing of Generation reserves	Que - NB NB - PEI NB - NS NB - NE	730 - 930 MW 40 - 140 MW 400 MW 30 - 1000 MW			Yes through the Maritime Power Pool.
	Seasonal Diversity Exchanges	NB NE	Winter peaking Summer Peaking for 30 years	150	$1.1	
	Summer Sales	NB to NE	30 years sale at 80% seasonal c.f.	250	$1.0	
	Long Term Firm Sales	NB - PEI	30 years sale up to 80% c.f.	50	$0.4	NB sale to PEI include 50 MW and 20 MW from Lepreau #1
		NB - Que				NB sale of 400 MW G.T. to Quebec
		Combined NB/NS Sale to NE	Construction of Lepreau #2 and coal gen. in NS to defer Nat. gas gen. in NE	600 600 1200	$2.3	NB has up to 230 MW of firm exports to NE from the Lepreau #1 nuclear unit.

APPENDIX 1

LEVELIZED UNIT ENERGY COST ANALYSIS

OF FUTURE GENERATING STATIONS

A - Levelized Unit Energy Cost (LUEC) of Capital Expenditure
(Capital cost per kW.h)

Calculate the Capital LUEC of a generating station ($ per kW.h of produced electricity), discounted to the in-service date T of the station, expressed in $ of the year T.

The following assumptions have been used in the LUEC calculation :

- Number of years between the in-service date T and 1990 : t ;
- Price of electricity in the year T, in current $ per kW.h : $P_{T,a}$;
- Annual generated electicity, in kW.h : E ;
- Nominal discount rate (%) : d ;
- Real discount rate (%) : r ;
- Inflation rate (%) : i ;
- Escalation rate, in current $ (%) : f ;
- Escalation rate, in constant $ (%) : e .

The nominal discount rate can be stated as a function of the real discount rate and the inflation rate :

$$(1 + d) = (1 + r)\ (1 + i)\ ; \qquad [1]$$

the escalation rates, in current $ and in constant $, can be related to each other :

$$(1 + f) = (1 + e)\ (1 + i)\ .$$

Other assumptions are the project overnight capital cost (without interest during construction) :

- in constant $ of the year 1990 : K_0 ;

and the annual disbursements for a 3 year construction period, prior to the in-service date T :

- in the year T - 3, in $ of 1990 : K_{T-3} ;
- in the year T - 2, in $ of 1990 : K_{T-2} ;
- in the year T - 1, in $ of 1990 : K_{T-1} ;
- and $K_{T-3} + K_{T-2} + K_{T-1} = K_0$.

The annual disbursements, stated in current $ of the year they are made, are:

- in $ of the year T - 3: $L_{T-3} = K_{T-3}(1+f)^{t-3} = K_{T-3}(1+e)^{t-3}(1+i)^{t-3}$; [2]

- in $ of the year T - 2: $L_{T-2} = K_{T-2}(1+f)^{t-2} = K_{T-2}(1+e)^{t-2}(1+i)^{t-2}$; [3]

- in $ of the year T - 1: $L_{T-1} = K_{T-1}(1+f)^{t-1} = K_{T-1}(1+e)^{t-1}(1+i)^{t-1}$. [4]

Assuming that the outlays L_{T-1}, L_{T-2} and L_{T-3} are made at the beginning of the year, then the interest during construction (IDC) accumulated in years T - 3, T - 2, T - 1, in current $, are :

$$Int_{T-3} = L_{T-3}\, d;$$

$$Int_{T-2} = (L_{T-3} + L_{T-3} d)\, d + L_{T-2} d;$$

$$Int_{T-1} = [L_{T-3} + L_{T-3} d + L_{T-2} + L_{T-3}(1+d)d + L_{T-2} d]\, d + L_{T-1} d$$

$$= [L_{T-3}(1+d) + L_{T-3}(1+d)d + L_{T-2}(1+d)]\, d + L_{T-1} d$$

$$= L_{T-3}(1+d)(1+d)d + L_{T-2}(1+d)d + L_{T-1} d.$$

Add all capital expenditures and discount the total to the in-service date T :

Adding the above equations gives the sum of all capital expenditures, in $ of the year T .

$$CAP = L_{T-3} + Int_{T-3} + L_{T-2} + Int_{T-2} + L_{T-1} + Int_{T-1}$$

$$= L_{T-3} + L_{T-3} d + L_{T-2} + L_{T-3}(1+d)d + L_{T-2} d + L_{T-1} +$$

$$+ L_{T-3}(1+d)^2 d + L_{T-2}(1+d)d + L_{T-1} d$$

$$= L_{T-3}(1+d) + L_{T-3}(1+d)d + L_{T-3}(1+d)^2 d + L_{T-2}(1+d) +$$

$$+ L_{T-2}(1+d)d + L_{T-1}(1+d)$$

$$= L_{T-3}(1+d)[1 + d + (1+d)d] + L_{T-2}(1+d)(1+d) + L_{T-1}(1+d)$$

$$CAP = L_{T-3}(1+d)^3 + L_{T-2}(1+d)^2 + L_{T-1}(1+d).$$

Substituting $(1+d)$, L_{T-3}, L_{T-2} and L_{T-1} with equations [1], [2], [3] and [4], the sum CAP is :

$$CAP = K_{T-3}(1+f)^{t-3}(1+d)^3 + K_{T-2}(1+f)^{t-2}(1+d)^2 + K_{T-1}(1+f)^{t-1}(1+d)$$

[5]

$$CAP = K_{T-3}(1+e)^{t-3}(1+i)^{t-3}(1+r)^3(1+i)^3 +$$
$$+ K_{T-2}(1+e)^{t-2}(1+i)^{t-2}(1+r)^2(1+i)^2 +$$
$$+ K_{T-1}(1+e)^{t-1}(1+i)^{t-1}(1+r)(1+i)$$
$$= K_{T-3}(1+e)^{t-3}(1+i)^{t}(1+r)^3 + K_{T-2}(1+e)^{t-2}(1+i)^{t}(1+r)^2 +$$
$$+ K_{T-1}(1+e)^{t-1}(1+i)^{t}(1+r)$$
$$CAP = (1+e)^{t-3}(1+i)^{t}(1+r)\,[K_{T-3}(1+r)^2 + K_{T-2}(1+e)(1+r) +$$
$$+ K_{T-1}(1+e)^2]. \qquad [6]$$

Calculate the revenues during the entire life of the generating station and discount the total to the in-service date T :

The annual revenue from the sale of electricity in the year X, in current $, is :

$$R_{X,a} = P_{X,a}\,E = P_{T,a}\,(1+i)^{X-T}\,E;$$

and discounted to the year T, it is : $\dfrac{R_{X,a}}{(1+d)^{X-T}} = \dfrac{P_{T,a}\,(1+i)^{X-T}\,E}{(1+d)^{X-T}}$

$$= \frac{P_{T,a}\,(1+i)^{X-T}\,E}{(1+r)^{X-T}\,(1+i)^{X-T}} = P_{T,a}\left[\frac{E}{(1+r)^{X-T}}\right]$$

Adding the revenues during N years of operation (power plant life), from T to T + N, and discounting the total to the in-service date T, the present worth of these revenues, in $ of the year T, is :

$$REV_a = \sum_{X=T}^{T+N}\left[\frac{P_{T,a}\,(1+i)^{X-T}\,E}{(1+d)^{X-T}}\right] = P_{T,a}\left\{\sum_{X=T}^{T+N}\left[\frac{E}{(1+r)^{X-T}}\right]\right\} \qquad [7]$$

Calculate the LUEC of Capital Expenditures ($P_{T,a}$):

The present worth of all the revenues, during the entire life of the generating station, should equal to the sum of all capital expenditures :

$$REV_a = CAP \qquad [8]$$

Equation [7] is equal to equation [5]:

$$\sum_{X=T}^{T+N} \left[\frac{P_{T,a}\,(1+i)^{X-T}\,E}{(1+d)^{X-T}} \right] = (1+f)^{t-3}(1+d)\,[K_{T-3}(1+d)^2 + K_{T-2}(1+f)(1+d) + K_{T-1}(1+f)^2]. \qquad [9]$$

Or equation [7] is equal to equation [6]:

$$P_{T,a}\left\{\sum_{X=T}^{T+N}\left[\frac{E}{(1+r)^{X-T}}\right]\right\} = (1+e)^{t-3}(1+i)^{T}(1+r)\,[K_{T-3}(1+r)^2 + K_{T-2}(1+e)(1+r) + K_{T-1}(1+e)^2]. \qquad [10]$$

Assuming in equation [9] that $P_{T,a}$ is constant and dividing the right member by the left member, the LUEC of Capital Expenditures, in $/kW.h of in-service date T, is:

$$P_{T,a} = \frac{(1+f)^{t-3}(1+d)\,[K_{T-3}(1+d)^2 + K_{T-2}(1+f)(1+d) + K_{T-1}(1+f)^2]}{\sum_{X=T}^{T+N}\left[\frac{(1+i)^{X-T}\,E}{(1+d)^{X-T}}\right]}. \qquad [11]$$

Doing the same with equation [10], the LUEC can be stated as a function of the constant escalation rate (e) and the real discount rate (r), in $/kW.h of the year T:

$$P_{T,a} = \frac{(1+e)^{t-3}(1+i)^{t}(1+r)\,[K_{T-3}(1+r)^2 + K_{T-2}(1+e)(1+r) + K_{T-1}(1+e)^2]}{\sum_{X=T}^{T+N}\left[\frac{E}{(1+r)^{X-T}}\right]}. \qquad [12]$$

To state the LUEC, calculated in equations [11] or [12], in $/kW.h of the year 1990, we divide it by $(1+i)^t$, i being the annual inflation rate between 1990 and the in-service date T, t being the number of years between 1990 and the in-service date.

Note:

$$\sum_{X=1}^{N}\left[\frac{(1+i)^{X}}{(1+d)^{X}}\right] = \frac{1+i}{1+d} + \frac{1+i}{1+d}\,\frac{1+i}{1+d} + \frac{1+i}{1+d}\,\frac{1+i}{1+d}\,\frac{(1+i)^2}{(1+d)^2} + \ldots + \frac{1+i}{1+d}\,\frac{(1+i)^{N-1}}{(1+d)^{N-1}}$$

$$= a + a\,v + a\,v^2 + \ldots + a\,v^{N-1}$$

$$= \frac{a\,(1-v^N)}{1-v} \qquad [13]$$

B - Levelized Unit Energy Cost (LUEC) of O.& M. Expenditures
(O.& M. cost per kW.h)

Calculate the O.& M. LUEC of a generating station ($ per kW.h of produced electricity), discounted to the in-service date T of the station, expressed in $ of the year T.

The following assumptions have been used in the LUEC calculation :

- Number of years between the in-service date T and 1990 : t ;
- Price of electricity in the year T, in current $ per kW.h : $P_{T,b}$;
- Annual generated electicity, in kW.h : E ;
- Nominal discount rate (%) : d ;
- Real discount rate (%) : r ;
- Inflation rate (%) : i ;
- Escalation rate, in current $ (%) : f ;
- Escalation rate, in constant $ (%) : e .

The nominal discount rate can be stated as a function of the real discount rate and the inflation rate :

$$(1 + d) = (1 + r)\ (1 + i)\ ; \qquad [1]$$

the escalation rates, in current $ and in constant $, can be related to each other :

$$(1 + f) = (1 + e)\ (1 + i)\ .$$

Other assumption is the station annual O.& M. cost, in constant $ of the year 1990 : B_0 .

or in $ of the year X when they are incurred :

$$B_X = B_0\ (1 + f)^{X-1990} = B_0\ (1 + f)^{X-T}\ (1 + f)^t = B_0\ (1 + e)^{X-T}\ (1 + i)^{X-T}\ (1 + e)^t\ (1 + i)^t$$

Add all O.& M. disbursements for the entire life of the generating station and discount the total to the in-sevice date T :

The O.& M. cost in year X, discounted to the in service date T, is : $\dfrac{B_0\ (1 + f)^{X-T}\ (1 + f)^t}{(1 + d)^{X-T}}$

and substituting $(1 + d)$ with equation [1], it is : $$\frac{B_0 (1+e)^{X-T} (1+i)^{X-T} (1+e)^t (1+i)^t}{(1+r)^{X-T} (1+i)^{X-T}}$$

$$= \frac{B_0 (1+e)^{X-T} (1+e)^t (1+i)^t}{(1+r)^{X-T}}$$

The total, for N years of operation is : $$O\&M = \sum_{X=T}^{T+N} \left[\frac{B_0 (1+f)^{X-T} (1+f)^t}{(1+d)^{X-T}} \right]$$

$$= B_0 (1+e)^t (1+i)^t \left[\sum_{X=T}^{T+N} \left[\frac{(1+e)^{X-T}}{(1+r)^{X-T}} \right] \right] \quad [2]$$

Calculate the revenues during the entire life of the generating station and discount the total to the in-service date T :

The annual revenue from the sale of electricity in the year X, in current $, is :

$$R_{X,b} = P_{X,b} E = P_{T,b} (1+i)^{X-T} E ;$$

and discounted to the year T, it is : $$\frac{R_{X,b}}{(1+d)^{X-T}} = \frac{P_{T,b} (1+i)^{X-T} E}{(1+d)^{X-T}}$$

$$= \frac{P_{T,b} (1+i)^{X-T} E}{(1+r)^{X-T} (1+i)^{X-T}} = P_{T,b} \left[\frac{E}{(1+r)^{X-T}} \right]$$

Adding the revenues during N years of operation (power plant life), from T to T + N, and discounting the total to the in-service date T, the present worth of these revenues, in $ of the year T, is :

$$REV_b = \sum_{X=T}^{T+N} \left[\frac{P_{T,b} (1+i)^{X-T} E}{(1+d)^{X-T}} \right] = P_{T,b} \left[\sum_{X=T}^{T+N} \left[\frac{E}{(1+r)^{X-T}} \right] \right] \quad [3]$$

Calculate the LUEC of O.& M. Expenditures ($P_{T,b}$) :

The present worth of the annual revenues, during the entire life of the generating station, should equal to the present worth of all O.& M. disbursements :

$$REV_b = O\&M \quad [4]$$

Equation [3] is equal to equation [2]:

$$\sum_{X=T}^{T+N} \left[\frac{P_{T,b} (1+i)^{X-T} E}{(1+d)^{X-T}} \right] = B_0 (1+f)^t \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+f)^{X-T}}{(1+d)^{X-T}} \right] \right\} \quad [5]$$

or :

$$P_{T,b} \left\{ \sum_{X=T}^{T+N} \left[\frac{E}{(1+r)^{X-T}} \right] \right\} = B_0 (1+e)^t (1+i)^t \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+e)^{X-T}}{(1+r)^{X-T}} \right] \right\} \quad [6]$$

Assuming in equation [5] that $P_{T,b}$ is constant and dividing the right member by the left member, the LUEC of O.& M. Expenditures, in $/kW.h of in-service date T, is :

$$P_{T,b} = \frac{B_0 (1+f)^t \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+f)^{X-T}}{(1+d)^{X-T}} \right] \right\}}{\sum_{X=T}^{T+N} \left[\frac{(1+i)^{X-T} E}{(1+d)^{X-T}} \right]} \quad [7]$$

Doing the same with equation [6], the LUEC can be stated as a function of the constant escalation rate (e) and the real discount rate (r), in $/kW.h of the year T :

$$P_{T,b} = \frac{B_0 (1+e)^t (1+i)^t \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+e)^{X-T}}{(1+r)^{X-T}} \right] \right\}}{\sum_{X=T}^{T+N} \left[\frac{E}{(1+r)^{X-T}} \right]} \quad [8]$$

To state the LUEC, calculated in equations [7] or [8], in $/kW.h of the year 1990, we divide it by $(1+i)^t$, i being the annual inflation rate between 1990 and the in-service date T, t being the number of years between 1990 and T.

Note :

$$\sum_{X=1}^{N} \left[\frac{(1+i)^X}{(1+d)^X} \right] = \frac{1+i}{1+d} + \frac{1+i}{1+d}\frac{1+i}{1+d} + \frac{1+i}{1+d}\frac{1+i}{1+d}\frac{(1+i)^2}{(1+d)^2} + \ldots + \frac{1+i}{1+d}\frac{(1+i)^{N-1}}{(1+d)^{N-1}}$$

$$= a + a\,v + a\,v^2 + \ldots + a\,v^{N-1}$$

$$= \frac{a\,(1-v^N)}{1-v} \quad [9]$$

C - Levelized Unit Energy Cost (LUEC) of Fuel Expenditures
(Fuel cost per kW.h)

Calculate the Fuel LUEC of a generating station ($ per kW.h of produced electricity), discounted to the in-service date T of the station, expressed in $ of the year T.

The following assumptions have been used in the LUEC calculation :

- Number of years between the in-service date T and 1990 : t ;
- Price of electricity in the year T, in current $ per kW.h : $P_{T,c}$;
- Annual generated electicity, in kW.h : E ;
- Annual fuel quantity required, in tonnes : Q ;
- Nominal discount rate (%) : d ;
- Real discount rate (%) : r ;
- Inflation rate (%) : i ;
- Escalation rate, in current $ (%) : f ;
- Escalation rate, in constant $ (%) : e .

The nominal discount rate can be stated as a function of the real discount rate and the inflation rate :

$$(1 + d) = (1 + r)\ (1 + i)\ ; \qquad [1]$$

the escalation rates, in current $ and in constant $, can be related to each other :

$$(1 + f) = (1 + e)\ (1 + i)\ .$$

Other assumption is the fuel price, in constant $/tonne of the year 1990 : C_0 ;

or in $/tonne of the year X when the fuel is bought :

$$C_X = C_0\ (1 + f)^{X-1990} = C_0\ (1 + f)^{X-T}\ (1 + f)^t = C_0\ (1 + e)^{X-T}\ (1 + i)^{X-T}\ (1 + e)^t\ (1 + i)^t$$

Add all Fuel disbursements for the entire life of the generating station and discount the total to the in-sevice date T :

The annual fuel cost in year X, associated with the average generated electricity E, is :

$$G_X = C_X Q;$$

and discounted to the year T, it is : $$\frac{G_X}{(1+d)^{X-T}} = C_0 (1+f)^t Q \left[\frac{(1+f)^{X-T}}{(1+d)^{X-T}} \right]$$

Substituting (1 + d) with equation [1] the discounted fuel cost is :

$$C_0 (1+e)^t (1+i)^t Q \left[\frac{(1+e)^{X-T} (1+i)^{X-T}}{(1+r)^{X-T} (1+i)^{X-T}} \right] = C_0 (1+e)^t (1+i)^t Q \left[\frac{(1+e)^{X-T}}{(1+r)^{X-T}} \right]$$

The total, for N years of operation is : $$FUEL = C_0 (1+f)^t Q \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+f)^{X-T}}{(1+d)^{X-T}} \right] \right\}$$

$$= C_0 (1+e)^t (1+i)^t Q \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+e)^{X-T}}{(1+r)^{X-T}} \right] \right\} \quad [2]$$

Calculate the revenues during the entire life of the generating station and discount the total to the in-service date T :

The annual revenue from the sale of electricity in the year X, in current $, is :

$$R_{X,c} = P_{X,c} E = P_{T,c} (1+i)^{X-T} E;$$

and discounted to the year T, it is : $$\frac{R_{X,c}}{(1+d)^{X-T}} = \frac{P_{T,c} (1+i)^{X-T} E}{(1+d)^{X-T}}$$

$$= \frac{P_{T,c} (1+i)^{X-T} E}{(1+r)^{X-T} (1+i)^{X-T}} = P_{T,c} \left[\frac{E}{(1+r)^{X-T}} \right]$$

Adding the revenues during N years of operation (power plant life), from T to T + N, and discounting the total to the in-service date T, the present worth of these revenues, in $ of the year T, is :

$$REV_c = \sum_{X=T}^{T+N} \left[\frac{P_{T,c} (1+i)^{X-T} E}{(1+d)^{X-T}} \right] = P_{T,c} \left\{ \sum_{X=T}^{T+N} \left[\frac{E}{(1+r)^{X-T}} \right] \right\} \quad [3]$$

Calculate the LUEC of FUEL Expenditures ($P_{T,c}$):

The present worth of the annual revenues, during the entire life of the generating station, should equal to the present worth of all fuel disbursements :

$$REV_c = FUEL \qquad [4]$$

Equation [3] is equal to equation [2]:

$$\sum_{X=T}^{T+N} \left[\frac{P_{T,c} (1+i)^{X-T} E}{(1+d)^{X-T}} \right] = C_o (1+f)^t Q \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+f)^{X-T}}{(1+d)^{X-T}} \right] \right\} \qquad [5]$$

or :

$$P_{T,c} \left\{ \sum_{X=T}^{T+N} \left[\frac{E}{(1+r)^{X-T}} \right] \right\} = C_o (1+e)^t (1+i)^t Q \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+e)^{X-T}}{(1+r)^{X-T}} \right] \right\} \qquad [6]$$

Assuming in equation [5] that $P_{T,c}$ is constant and dividing the right member by the left member, the LUEC of Fuel Expenditures, in $/kW.h of in-service date T, is :

$$P_{T,c} = \frac{C_o (1+f)^t Q \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+f)^{X-T}}{(1+d)^{X-T}} \right] \right\}}{\sum_{X=T}^{T+N} \left[\frac{(1+i)^{X-T} E}{(1+d)^{X-T}} \right]} \qquad [7]$$

Doing the same with equation [6], the LUEC can be stated as a function of the constant escalation rate (e) and the real discount rate (r), in $/kW.h of the year T :

$$P_{T,c} = \frac{C_o (1+e)^t (1+i)^t Q \left\{ \sum_{X=T}^{T+N} \left[\frac{(1+e)^{X-T}}{(1+r)^{X-T}} \right] \right\}}{\sum_{X=T}^{T+N} \left[\frac{E}{(1+r)^{X-T}} \right]} \qquad [8]$$

To state the LUEC, calculated in equations [7] or [8], in $/kW.h of the year 1990, we divide it by $(1+i)^t$, i being the annual inflation rate between 1990 and the in-service date T, t being the number of years between 1990 and T.

D - Total Levelized Unit Energy Cost (LUEC) of all expenditures
(Capital, O.& M. and Fuel costs per kW.h)

Calculate the total LUEC of a generating station ($ per kW.h of produced electricity), discounted to the in-service date T of the station, expressed in $ of the year T.

The present worth of all annual revenues, during the entire life of the generating station, should equal to the present worth of all disbursements (capital, O.& M. and fuel) :

$$REV_a + REV_b + REV_c = CAP + O\&M + FUEL .$$

It was established in the previous sections that REV_a is equal to CAP, REV_b is equal to O & M, and REV_c is equal to FUEL.

It was also determined that the LUEC of capital expenditures $P_{T,a}$ is a function of REV_a and CAP, the LUEC of O.& M. expenditures $P_{T,b}$ is a function of REV_b and O & M, and the LUEC of fuel expenditures $P_{T,c}$ is a function of REV_c and FUEL.

The total LUEC of a generating station, discounted to the in-service date T of the station and expressed in $/kW.h of the year T, is consisted of the capital, O.& M. and fuel components :

$$P_{T,total} = P_{T,a} + P_{T,b} + P_{T,c} .$$

To state the total LUEC, calculated in the above equation, in $/kW.h of the year 1990, we divide it by $(1 + i)^t$, i being the annual inflation rate between 1990 and the in-service date T, t being the number of years between 1990 and T.

E - Calculation of Total Expenditures using the Total Levelized Unit Energy Cost (LUEC)

The LUEC $P_{T,total}$ (calculated in the previous sections) can be used to figure out the total expenditures EXP over a specified time period N associated with the generation of an annual energy E, discounted to the reference year T at a specified real discount rate r :

$$EXP = P_{T,total}\ E \left\{ \sum_{X=1}^{N} \left[\frac{1}{(1+r)^X} \right] \right\}$$

$$= P_{T,total}\ E \left[\frac{a\,(1 - v^N)}{1 - v} \right] \qquad \text{where } a = v = \frac{1}{(1+r)}$$

The following table gives the multiplying factor to be used to calculate EXP, discounted to the beginning of the year T at a real discount rate of 6.0 % :

N	Multiplying Factor
1	$\frac{0.94340\ (1 - 0.94340^{1})}{1 - 0.94340} = 0.94340$
5	$\frac{0.94340\ (1 - 0.94340^{5})}{1 - 0.94340} = 4.21241$
10	$\frac{0.94340\ (1 - 0.94340^{10})}{1 - 0.94340} = 7.36023$
15	$\frac{0.94340\ (1 - 0.94340^{15})}{1 - 0.94340} = 9.71252$
20	$\frac{0.94340\ (1 - 0.94340^{20})}{1 - 0.94340} = 11.47032$
25	$\frac{0.94340\ (1 - 0.94340^{25})}{1 - 0.94340} = 12.78387$
30	$\frac{0.94340\ (1 - 0.94340^{30})}{1 - 0.94340} = 13.76546$
60	$\frac{0.94340\ (1 - 0.94340^{60})}{1 - 0.94340} = 16.16245$

LEVELIZED UNIT ENERGY COST ANALYSIS

1.	Project :	NB - Power Belledune Unit 1 (with scrubber)				
2.	Capacity :	440.0	(440 x 1)	MW		
3.	Capacity factor :	80.0%				
4.	Average annual energy :		3,083.5	GWh		
5.	Heat rate or efficiency =		35.5%	or	10,149.1	KJ/kWh
6.	Construction period :	5.0	years			
7.	Station life :	35.0	years			
8.	Fuel :	Bituminous coal (medium sulphur content); no.6 fuel oil can also be used.				
9.	Source :	North America				
10.	Fuel heat content :	30.46	MJ/kg	or	13,100.0	Btu/lbs
11.	Fuel price in 1990 :	$62.13	$/tonne	($ of 1990)		
12.	Fuel price escalation rate :		-0.3%	(real term)		
13.	Real discount rate :	6.0%				
14.	In-service date :	2000				
15.	Capital cost (discounted to 1990) :		374.9	millions	($ of 1990)	
16.	Operating cost (discounted to 1990) :		310.6	millions	($ of 1990)	
17.	Fuel cost (discounted to 1990) :		406.4	millions	($ of 1990)	
18.	Total cost (discounted to 1990) :		1,092.0	millions	($ of 1990)	

LUEC =	43.74	mills/kWh	(mill of 1990)

N.B. POWER **BELLEDUNE UNIT 1 Coal / Oil Fired Generating Station**

Capital cost = 810.4 millions (1994 $) [1] Capacity = 440.0 (440x1) MW Capacity factor = 80.0% 3,083.5 GWh
(w/o transmission, w/o IDC)

Capital cost = 1,067.9 millions ($ of 2000, in-service date)
(w/o transmission, but incl. IDC)

Capital cost per kW = 2,427.0 ($ of 2000)
1,526.0 ($ of 1990)

Discount rate = 6.0% (real), 10.2% (nominal)
(from year 2000)

Station life = 35.0 years

	discount to in-service date (2000 mills)	(1990 mills)
Capital cost per kWh	23.89	15.02
Operating cost per kWh	19.79	12.44
Fuel cost per kWh	25.89	16.28
Levelized cost per kWh	69.57	43.74

Capacity factor = 60.0% 2,312.6 GWh

	discount to in-service date (2000 mills)	(1990 mills)
Capital cost per kWh	31.85	20.03
Operating cost per kWh	26.39	16.59
Fuel cost per kWh	25.89	16.28
Levelized cost per kWh	84.13	52.90

Note : [1] Overnight capital cost is 943.3 millions ($ of 1994) for plant (from NB Power response to Interprovincial Coord. Study - Oct/91)

(ASSUMED COST OF ENERGY AT SITE).

N.B. POWER **BELLEDUNE UNIT 1 Coal / Oil Fired Generating Station**

Capital cost = 943.3 millions ($ of 1994)

806.3 millions ($ of 1990) [2]

(w/o transmission, includes IDC)

Total Capital cost = 1,067.9 millions ($ of 2000)

discounted to 1990 = 374.9 millions ($ of 1990)

(w/o transmission, but incl. IDC)

Capital cost per kWh

		discount to in-service date (2000 mills)	(1990 mills)	discount to 1990
capacity factor	80.0%	23.89	15.02	15.02
capacity factor	60.0%	31.85	20.03	20.03

Discount rate = 6.0% (real), 10.2% (nominal)
(from year 2000)

Station life = 35.0 years

CAPITAL COSTS (million $)

Year	1992	1993	1994	1995	1996	1997	1998	1999	in-service 2000	Total
Disbursement :										
(in 1990 $)				72.6	129.0	161.3	258.0	185.5	0.0	806.3
(% total cost) [3]				9.0%	16.0%	20.0%	32.0%	23.0%	0.0%	100.0%
(in current $)				88.3	162.5	210.2	348.1	258.9	0.0	1,067.9
factor	1.1									
I.D.C.									0.0	0.0
CWIP incl.interest :										
(current $)				88.3	162.5	210.2	348.1	258.9	0.0	1,067.9
				0.0	0.0	0.0	0.0	0.0		

Notes : [2] Overnight capital cost is $943.3 ($ of 1994) for plant (from NB Power response to Interprovincial Trade review (Oct/91)

[3] Capital cost layout based on employment data from NB Power Belledune 450 MW Thermal Generating Station, Environmental Impact Assessment Report, July 1989.

N.B. POWER **BELLEDUNE UNIT 1 Coal / Oil Fired Generating Station**

Annual Operating Costs (millions)

	$ of 1994 [4]	$ of 1990
O & M	44.0	36.2
Administration		
Insurance		
Interim replacemnt		
Flue Gas Desulp.	----	----
Total	44.0	36.2

Operating cost per kWh

		discount to in-service date (2000 mills)	(1990 mills)	discount to 1990
capacity factor	80.0%	19.79	12.44	12.44
capacity factor	60.0%	26.39	16.59	16.59

Discount rate = 6.0% (real), 10.2% (nominal)
(from year 2000)

Station life = 35.0 years

Total Operating costs :

discounted to 2000 = 884.8 millions ($ of 2000)

discounted to 1990 = 310.6 millions ($ of 1990)

ANNUAL OPERATING COSTS (million current $)

Year	In-service 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 - ...
O & M	57.6	59.9	62.3	64.8	67.4	70.0	72.8	75.8	78.8	81.9
Administration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance										
Interim replacemnt	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flue Gas Desulp.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	57.6	59.9	62.3	64.8	67.4	70.0	72.8	75.8	78.8	81.9
Discount to 2000 (in-service date)	57.6	54.3	51.2	48.3	45.6	43.0	40.6	38.3	36.1	34.1

The escalation rate starting in the year 2001 is the C.P.I. = 4.0%

Note : [4] Annual operating costs from NB Power response to Interprovincial Coord. Study (Sept/91).

N.B. POWER **BELLEDUNE UNIT 1 Coal / Oil Fired Generating Station**

Fuel Characteristics : Bituminous coal (medium sulphur content)

Heat content = 13,100.0 BTU/lbs or 30.46 MJ/kg [5]

Heat rate or efficiency: 35.5% or 10,149.1 KJ/kWh [5]

Total Fuel costs : capacity factor : 80.0%

discounted to 2000 = 1,157.5 millions ($ of 2000)

discounted to 1990 = 406.4 millions ($ of 1990)

Fuel quantity required = 1,027.5 kilotonnes per year

Total Fuel costs : capacity factor : 60.0%

discounted to 2000 = 868.2 millions ($ of 2000)

discounted to 1990 = 304.8 millions ($ of 1990)

Fuel quantity required = 770.6 kilotonnes per year

Fuel cost per kWh

		discount to in-service date (2000 mills)	(1990 mills)	discount to 1990
capacity factor	80.0%	25.89	16.28	16.28
capacity factor	60.0%	25.89	16.28	16.28

Discount rate = 6.0% (real), 10.2% (nominal)
(from year 2000)

Station life = 35.0 years

ANNUAL FUEL COSTS (million current $)

Year		in-service 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 - ...	- ...	- ...	- ...
Cap. factor	80.0%	77.8	80.7	83.7	86.8	90.0	93.3	96.8	100.4	104.1	107.9	} Escalation rate starting } in the year 2001 =		3.7%
Discount to 2000 (in-service date)		77.8	73.2	68.9	64.8	60.9	57.3	53.9	50.7	47.7	44.9			
Capacity factor	60.0%	58.4	60.5	62.8	65.1	67.5	70.0	72.6	75.3	78.1	80.9	} Escalation rate starting } in the year 2001 =		3.7%
Discount to 2000 (in-service date)		58.4	54.9	51.6	48.6	45.7	43.0	40.4	38.0	35.8	33.7			

Note : [5] Heat content and heat rate adapted from NS Power The Bluenose Project, Nova Scotia - New England, May 1988.

LEVELIZED UNIT ENERGY COST ANALYSIS

ECONOMIC ASSUMPTIONS

Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001 - ...
Interest rate (nominal)	10.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	10.8%	10.8%	10.8%	10.8%	10.8%	10.2%	10.2%
Discount rate :														
Nominal	10.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	10.8%	10.8%	10.8%	10.8%	10.8%	10.2%	10.2%
Real	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
C.P.I.	4.1%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	4.5%	4.5%	4.5%	4.5%	4.5%	4.0%	4.0%
Conversion factor	$ of 2000 to $ of 1990 =				1.59048									
Construction Escalation rate (nominal)	3.1%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	3.5%	3.5%	3.5%	3.5%	3.5%	3.0%	3.0%
Bituminous coal :														
current $/GJ	$2.74	$2.83	$2.04	$2.08	$2.12	$2.16	$2.21	$2.25	$2.30	$2.34	$2.39	$2.44	$2.49	$2.58
current $/tonne	$83.45	$86.19	$62.13	$63.38	$64.64	$65.94	$67.25	$68.60	$69.97	$71.37	$72.80	$74.25	$75.74	$78.54
	nominal escalation rate from 1988 to 2000 =					2.0%				nominal escalation rate from 2000 =				3.7%

Note : Most assumptions based on data provided by Economic Branch, May-July 1989.
Fuel data obtained from NOVA SCOTIA information - info received from New Brunswick amounted to $2.34/GJ in 1990 (Nova Scotia says $2.04/GJ in Jan/90), so the Nova Scotia value was used for consistancy.

Appendix 2

Levelized Unit Energy Cost Analysis

Economic and Fuel Cost Assumptions

FUEL PRICE ASSUMPTIONS

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Newfoundland														
Heavy fuel oil :														
current $/GJ	$2.36	$2.64	$2.68	$2.89	$3.13	$3.38	$3.65	$3.94	$4.25	$4.59	$4.96	$5.36	$5.79	$6.25
current $/m3	$98.51	$110.20	$111.87	$120.82	$130.48	$140.92	$152.20	$164.37	$177.52	$191.72	$207.06	$223.63	$241.52	$260.84
	nominal escalation rate from 1990 to 2000 =					8.0%				nominal escalation rate from 2000 =				7.4%
Nova Scotia														
Bituminous coal :														
current $/GJ	$2.74	$2.83	$2.04	$2.08	$2.12	$2.16	$2.21	$2.25	$2.30	$2.34	$2.39	$2.44	$2.49	$2.58
current $/tonne	$83.45	$86.19	$62.13	$63.38	$64.64	$65.94	$67.25	$68.60	$69.97	$71.37	$72.80	$74.25	$75.74	$78.54
	nominal escalation rate from 1988 to 2000 =					2.0%				nominal escalation rate from 2000 =				3.7%
Prince Edward Island														
Light fuel oil :														
current $/GJ	$5.51	$5.56	$5.62	$5.97	$6.34	$6.74	$7.16	$7.60	$8.08	$8.58	$9.12	$9.69	$10.30	$10.98
current $/m3	$220.09	$222.13	$224.24	$238.26	$253.15	$268.97	$285.78	$303.64	$322.62	$342.79	$364.21	$386.97	$411.16	$438.30
	nominal escalation rate from 1990 to 2000 =					6.3%				nominal escalation rate from 2000 =				6.6%
New Brunswick														
Bituminous coal :														
current $/GJ	$2.74	$2.83	$2.04	$2.08	$2.12	$2.16	$2.21	$2.25	$2.30	$2.34	$2.39	$2.44	$2.49	$2.58
current $/tonne	$83.45	$86.19	$62.13	$63.38	$64.64	$65.94	$67.25	$68.60	$69.97	$71.37	$72.80	$74.25	$75.74	$78.54
	nominal escalation rate from 1988 to 2000 =					2.0%				nominal escalation rate from 2000 =				3.7%
Natural uranium :														
current $/GJ	$0.31	$0.32	$0.20	$0.20	$0.20	$0.20	$0.21	$0.21	$0.22	$0.22	$0.22	$0.23	$0.23	$0.24
current $/kgU	$223.18	$230.38	$146.11	$146.11	$146.11	$146.11	$149.03	$152.01	$155.05	$158.15	$161.31	$164.54	$167.83	$174.04
	nominal escalation rate from 1990 to 2000 =					2.0%				nominal escalation rate from 2000 =				3.7%

FUEL PRICE ASSUMPTIONS

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Ontario														
Natural uranium :														
current $/GJ	$0.49	$0.50	$0.50	$0.51	$0.52	$0.53	$0.54	$0.55	$0.56	$0.57	$0.59	$0.60	$0.61	$0.63
current $/kgU	$352.77	$359.97	$359.97	$367.17	$374.51	$382.00	$389.64	$397.44	$405.39	$413.49	$421.76	$430.20	$438.80	$455.04
nominal escalation rate from 1990 to 2000 =						2.0%				nominal escalation rate from 2000 =				3.7%
U.S. Bitminous coal :														
current $/GJ	$2.66	$2.74	$2.74	$2.79	$2.85	$2.91	$2.97	$3.03	$3.09	$3.15	$3.21	$3.27	$3.34	$3.46
current $/tonne	$78.73	$81.10	$81.10	$82.72	$84.37	$86.06	$87.78	$89.54	$91.33	$93.15	$95.02	$96.92	$98.86	$102.51
nominal escalation rate from 1990 to 2000 =						2.0%				nominal escalation rate from 2000 =				3.7%
Natural gas (industrial sector) :														
current $/GJ	$3.28	$3.15	$2.88	$3.28	$3.60	$3.98	$4.34	$4.65	$5.09	$5.58	$6.05	$6.54	$7.06	$7.41
current $/1000m3	$122.36	$117.51	$107.43	$122.36	$134.29	$148.47	$161.90	$173.46	$189.88	$208.16	$225.69	$243.97	$263.36	$276.53
nominal escalation rate from 1990 to 2000 =										nominal escalation rate from 2000 =				5.0%
Saskatchewan														
Lignite coal :														
Lignite :														
current $/GJ	$0.78	$0.80	$0.72	$0.74	$0.75	$0.77	$0.78	$0.80	$0.81	$0.83	$0.85	$0.86	$0.88	$0.91
current $/tonne	$11.93	$12.23	$11.04	$11.26	$11.48	$11.71	$11.95	$12.19	$12.43	$12.68	$12.93	$13.19	$13.46	$13.95
nominal escalation rate from 1990 to 2000 =						2.0%				nominal escalation rate from 2000 =				3.7%
Alberta														
Sub-bituminous coal :														
current $/GJ	$0.47	$0.49	$0.49	$0.50	$0.51	$0.52	$0.53	$0.54	$0.55	$0.56	$0.57	$0.59	$0.60	$0.61
current $/tonne	$8.41	$8.77	$8.77	$8.95	$9.13	$9.31	$9.50	$9.69	$9.88	$10.08	$10.28	$10.48	$10.69	$10.91
nominal escalation rate from 1990 to 2000 =						2.0%				nominal escalation rate from 2000 =				3.7%
British Columbia														
Lignite coal (Hat Creek, B.C.) :														
Lignite (Hat Creek, B.C.) :														
current $/GJ	$0.78	$0.80	$0.82	$0.83	$0.85	$0.87	$0.88	$0.90	$0.92	$0.94	$0.96	$0.98	$0.99	$1.03
current $/tonne	$11.24	$11.53	$11.76	$12.00	$12.24	$12.48	$12.73	$12.99	$13.25	$13.51	$13.78	$14.06	$14.34	$14.87
nominal escalation rate from 1990 to 2000 =						2.0%				nominal escalation rate from 2000 =				3.7%

FUEL PRICE ASSUMPTIONS

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
New York														
U.S. Bituminous coal (New York) :														
current $/MBTU	$1.88	$1.87	$1.95	$2.02	$2.11	$2.19	$2.28	$2.37	$2.46	$2.56	$2.66	$2.77	$2.88	$3.03
current $/tonne	$52.82	$52.52	$54.62	$56.81	$59.08	$61.44	$63.90	$66.46	$69.11	$71.88	$74.75	$77.74	$80.85	$84.90
nominal escalation rate from 1990 to 2000 =						4.0%				nominal escalation rate from 2000 =				5.0%
Natural Gas (New York) :														
current $/MBTU	$3.42	$3.60	$3.80	$3.98	$4.16	$4.55	$4.94	$5.32	$5.71	$6.08	$6.64	$7.20	$7.76	$8.14
current $/1000m3	$119.00	$125.34	$132.05	$138.40	$144.74	$158.17	$171.60	$185.02	$198.45	$211.51	$230.91	$250.31	$269.70	$287.64
avg. nominal escalation rate from 1990 to 2000 =						7.2%				nominal escalation rate from 2000 =				5.0%
New England														
U.S. Bituminous coal (New England) :														
current $/MBTU	$2.06	$2.02	$2.10	$2.19	$2.28	$2.37	$2.46	$2.56	$2.66	$2.77	$2.88	$2.99	$3.11	$3.27
current $/tonne	$57.87	$56.76	$59.04	$61.40	$63.85	$66.41	$69.06	$71.83	$74.70	$77.69	$80.79	$84.03	$87.39	$91.76
nominal escalation rate from 1990 to 2000 =						4.00%				nominal escalation rate from 2000 =				5.00%
Natural Gas (New England) :														
current $/MBTU	$3.87	$4.08	$4.29	$4.50	$4.70	$5.12	$5.54	$5.94	$6.36	$6.78	$7.38	$7.98	$8.58	$9.01
current $/1000m3	$134.67	$141.75	$149.21	$156.30	$163.39	$177.94	$192.49	$206.66	$221.21	$235.76	$256.65	$277.54	$298.43	$319.19
avg. nominal escalation rate from 1990 to 2000 =						7.0%				nominal escalation rate from 2000 =				5.0%
Minnesota (MAPP) :														
U.S. Lignite coal (Minnesota) :														
current $/MBTU	$1.42	$1.43	$1.45	$1.48	$1.51	$1.54	$1.57	$1.60	$1.64	$1.67	$1.70	$1.74	$1.77	$1.84
current $/tonne	$17.58	$17.59	$17.94	$18.30	$18.67	$19.04	$19.42	$19.81	$20.21	$20.61	$21.03	$21.45	$21.87	$22.68
nominal escalation rate from 1990 to 2000 =						2.0%				nominal escalation rate from 2000 =				3.7%
California														
Natural Gas (California) :														
current $/MBTU	$3.24	$3.40	$3.56	$3.73	$3.89	$4.25	$4.60	$4.97	$5.32	$5.68	$6.24	$6.81	$7.38	$7.75
current $/1000m3	$112.66	$118.25	$123.85	$129.82	$135.41	$147.72	$160.03	$172.71	$185.02	$197.33	$217.11	$236.88	$256.65	$276.43
avg. nominal escalation rate from 1990 to 2000 =						7.30%				nominal escalation rate from 2000 =				5.00%

APPENDIX 3

TRANSMISSION COSTS

1.0 INTRODUCTION

Many factors can influence the cost of a transmission system, the most important of which are capacity, type and design as described below.

The current carry capacity or rating is the capability for transporting electric power which is mainly determined by the thermal qualities of a transmission system. As the capacity increases so does the design voltage. The reason for this is to reduce the transmission losses and voltage drop.

Besides the design capacity or rating, there are two operational constraints which limit the capability of transmission systems in transferring electric power. These constraints, the stability limit and voltage limit, are determined by system analysts and implemented by operators to ensure no degradation to the system security.

Transmission systems can be divided into two types; AC and DC. In practice, it is the application which determines the type of a transmission system. For a specific application, either AC or DC could be more economical depending on the capacity.

Finally transmission design, which affects the cost significantly, is heavily influenced by the terrain which the transmission line would traverse. For example, the design of a transmission system spanning over mountainous areas is very different from that for an undersea crossing.

The above points show that the cost of a transmission system cannot be estimated accurately unless all its specifications are known. For the purpose of this study, however, a simple costing method has been recommended which gives an approximate estimate of a transmission system cost.

2.0 COST ASSESSMENT

The National Regulatory Research Institute data adjusted to 1990 dollars gives the following costs for various types of transmission systems.

450 KV DC	0.72 million/km
138 KV	0.22 million/km
345 KV	0.32 million/km
500 KV	0.47 million/km
765 KV	0.72 million/km

These figures were used to obtain the following Levelized Unit Energy costs (LUEC) for the year 2000 using a 1000 MW, 1000 km transmission system with a capacity factor of 0.8 assuming a 30 year life.

Systems	Capital Cost per Kwh mills, year 2000
450 KV DC	11.6
345 KV	5.2
500 KV	7.6(1)
765 KV	11.6

In order to verify the accuracy of the above figures, the estimated capital cost for three Canadian projects obtained from the corresponding utilities were used to obtain their LUECs. The calculated LUECs for these projects are given below.

Project		Type	Levelized unit cost mills, year 2000
Hydro Québec	James Bay to New England	Overhead	9.2

(1) Ontario Hydro estimate approximately 30% higher.

F2

Gull Island		Partly undersea	26
Nova Scotia	Connection to Boston	Partly undersea	30

It should be noticed that the cost of an undersea cable transmission system is 3 to 4 times higher than the cost of an overhead transmission system. Therefore, depending on the amount of undersea capable required in a transmission system the cost could vary by 300%. Furthermore, for DC transmission systems, the cost of the DC converter stations alone comes to about 5.0 mills for a 1000 MW system.

3.0 RECOMMENDATION

As a rule of thumb, for the generation cost comparative analysis, it is suggested to use a value of 10 mills/Kwh/1000 km for overhead transmission systems. For transmission systems including partly undersea cable a value of 25 mills is recommended. Finally for a fully undersea cable transmission system a value of 35 mills is recommended. These values should be proportionally changed to reflect the length of the transmission lines required in the study.

APPENDIX 4

POTENTIAL SEASONAL DIVERSITY AND SUMMER SALES BETWEEN CANADIAN AND US UTILITIES

1. INTRODUCTION

All Canadian utilities are winter peaking systems and consequently have surplus capacity during the summer months. Many U.S. utilities on the other hand are summer peaking systems with surplus capacity during the winter months. Potential opportunities exist therefore for summer/winter seasonal diversity exchanges between Canadian and U.S. utilities. Also in lieu of seasonal diversity trade, summer sales opportunities also exist for Canadian utilities in those cases where Canadian utilities cannot be assured or don't plan to rely on return capacity from U.S. systems during the winter period.

It should also be noted that long term firm summer sales require the selling utility not only to have assured surplus summer capacity but also assured annual energy above its own domestic needs and other firm commitments to support such transactions. Therefore, in general systems which are predominantly thermal based and energy rich have a greater opportunity to engage in these types of sales than do hydro based systems. Hydro systems' energy capabilities are weather dependant and therefore may be energy constrained. Firm summer sales are still possible but they tend to be negotiated on a year to year basis depending on the availability of surplus hydro energy.

This broad brush assessment reviews the potential for seasonal diversity exchanges as well as long-term firm capacity summer sales between Canadian and U.S. selected utilities within each of the regions described in this report.

2. ASSUMPTIONS

The potential for seasonal diversity exchanges depends on the ability to use surplus capacity on one system to defer the building of generation on the other and vice-versa. However for every MW of capacity deferred there will be one less MW of surplus capacity available for seasonal diversity exchanges. Thus the maximum potential for reduction in generation is 50% of the lesser of the differences between the winter and summer peaks for each system. The realistic seasonal diversity potential however can be

much smaller because of a host of technical constraints. These include transmission limitations, scheduled maintenance of units, system stability and performance related problems, etc.

Although it is generally recognized that an electric utility's summer peaking period (i.e. usually from May to Oct.) is 6 months while its corresponding winter peak duration (i.e. Nov. to Feb.) is 4 months, for this seasonal diversity analysis it was assumed that the summer and winter periods would be identical (i.e. 6 months). It was also assumed that any seasonal diversity exchanges would be made at a seasonal capacity factor of 80% c.f. Summer sales on the other hand were assumed for a period of 6 months at 80% c.f. for those systems with assured energy over and above their domestic requirements and firm commitments.

3. BENEFITS AND COSTS FROM SEASONAL DIVERSITY EXCHANGES

Based on the above underlying assumptions, the net benefits from seasonal diversity exchanges were calculated as the difference between the utilities' generating facility capital deferments and the cost of the transmission necessary to make the exchanges. It was also assumed that the net energy production costs or savings in the summer period would be completely cancelled out during the subsequent winter period when energy is returned.

4. BENEFITS AND COSTS FROM LONG-TERM FIRM SUMMER CAPACITY SALES

The gross benefits from long-term summer sales were calculated as the savings from the difference between the systems' energy production costs and from the capacity that would have been deferred by the purchasing system. Cost on the other hand would be the cost of transmission facilities required to make the transactions.

5. RESULTS FROM A REGIONAL PERSPECTIVE

Although five regions were identified in this report, assessments of the seasonal diversity exchanges and summer sales opportunities in Regions #1, #2, #3, and #5 provided the full range of potential opportunities that might exist between the interconnected utilities.

5.1 Region #1: BC/Alta and California

BC and Alberta are winter peaking systems and consequently have surplus capacity during the summer periods. The same is true for U.S. utilities in the Pacific Northwest. Utilities in California on the other hand are summer peaking with surplus capacity during the winter months. Potential opportunities therefore exist for summer/winter seasonal diversity exchanges between utilities in the Pacific northwest including BC and Alberta and those in California. Even if U.S. utilities in the Pacific Northwest have priority over Canadian utilities to such diversity trade, there still appear to be opportunities for BC and Alberta to take advantage of the potential remaining seasonal diversity with California. In lieu of seasonal diversity exchanges there might also be potential for long-term summer sales (i.e. from May to Oct.) by BC/Alberta utilities into the California market.

Table #1 shows that even when taking into account the potential diversity trade between utilities in the U.S. Pacific Northwest and California, there still exists a potential for about 1000 MW(1) of seasonal diversity exchange and 2000 MW(1) of summer sales between the combined BC/Alberta systems and California by the year 2000. Summer sales require long term firm energy support. In the case of joint BC/Alberta sales to the U.S., the energy is assumed to come from Alberta because BC Hydro is energy limited. A cursory examination of the Alberta Interconnected system indicates surplus of this type available in the order of 3000 - 4000 GW.h/yr. Coupled with the fact that maintenance is preferentially performed in the summer months, we estimate that a reasonable summer sale potential would be 1000 MW. Similarly, a seasonal diversity exchange of 500 MW was assumed.

Tables 2 & 3 provide rough estimates of net benefits arising from the exploitation of the potential seasonal diversity exchanges and summer sales respectively (i.e. 500 MW diversity exchange and 1000 MW summer sale). These analyses were based on the following assumptions:

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(1) The respective systems summer/winter peak loads used in this analysis were obtained from the NERC 1990 Electricity Supply and Demand Report published in November 1990.

For Seasonal Diversity

- 500 MW summer/winter seasonal diversity exchange.
- The period of the contract was 30 years at 80 % seasonal capacity factor.
- The capital deferment in California was combined cycle generation at 18.4 mills/kW.h (ie. 89.9 - 71.5) (see figures # 3 and # 5 of the report).
- The capital deferment in Alberta was sub bituminous coal fired generation at 26.8 mills/kW.h (ie. 32.6 - 5.8).
- The capital deferment in BC was lignite coal fired generation at 38.7 mills/kW.h (ie. 50.2 - 11.5).
- The combined capital deferment in BC/Alta assuming a 50/50 split was 32.8 mills/kW.h.
- Additional transmission required to affect the exchanges between BC/Alta and California is estimated to be 2000 km at 20 mills/kW.h for each 1000 MW of transfer (see appendix 3).

For Summer Sales

In addition to the values listed above, the following assumptions were made:

- 1000 MW summer sale (i.e. 6 months) by BC/Alta to California
- The period of the contract was 30 years at 80 % seasonal capacity factor.
- Energy production costs in California = 71.5 mills/kW.h. (see figure #5 of the report)
- Energy production costs in Alberta = 5.8 mills/kW.h.
- Energy production costs in BC = 11.5 mills/kW.h.

REGION #1 BC/ALTA/CALIFORNIA

Table #1

Potential Magnitude of Seasonal diversity and Summer Sales

Systems	2000 Peak Load		Potential Capacity Sur. MW	Potential Diversity Exch. MW	Potential Sum. Sale MW
	Winter MW	Summer MW			
(1)	(2)	(3)	(4) = (2)-(3) s = summer w = winter	5 = (0.5)(4)	(6)=(4)
System Ch5.					
Combined BC-Alt	18 060	14 042	4018 (s)	2009 (s)	4018 (s)
U.S. N.West Pool	40 617	31 413	9204 (s)	4602 (s)	9204 (s)
California - So. Nev	43 062	54 383	11 321 (w)	5660 (s)	11 321 (w)
Pot. Diversity s/w					
U.S. NW & Calif.				4602 (s/w)	9204 (s)
(BC-Alt) & Calif.				1058 (s/w)	2117 (s)

Table #2

Net Potential Benefits from Seasonal Diversity Exchanges
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Amount of Diversity MW	Capital Deferm. mills/KWh			Trans. Cost mills/KWh	Net Benefits mills/KWh	CUM PW Factor (1)	Net Benefits $billions
		California	BC/Alt.	Total				
	(1)	(2)	(3)	(4) = (3)+(2)	(5)	(6) = (4)-(5)	(7)	(8) = (1)(6)(7)
BC/Alta with Calif.	500	18.4	32.8	51.2	20	31.2	96.5	$1.5 billion

Table #3

Net Potential Summer Benefits from Sales
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Amount of Summer Sale MW	Annual Energy Production			Energy Prod. Diff. 6 months	Capital Def. Calif.	Total Benefit mills/kWh	Trans. cost mills/kWh	Net Benefits mills/kWh	CUM(1) PW factor	Net Benefits $billions
		BC/Alt	Calif.	Diff.							
	(1)	(2)	3	(4) = (3)-(2)	(5) = 0.5(4)	(6)	(7) = (6)+(5)	(8)	(9) = (7)-(8)	(10)	(11)= (1)(9)(10)
BC/Alta to Calif.	1000	8.6	71.5	62.9	31.5	14.8	46.3	20.0	26.3	96.5	$2.5 billion

(1) (Annual energy @ 80% CF) (CUM discount factor over 30 years at 6% resl)

$$\frac{(8760)(0.8)(13.7655)}{1000} = 96.5$$ (see Appendix 1)

- Energy production costs for the combined BC/Alta assuming a 50/50 split = 8.65 mills/kW.h.

Table # 2 shows that the seasonal diversity benefits between the combined BC/Alberta systems and California based on a 500 MW, 30 year contract is estimated to be $1.5 billion.

Table # 3 shows that the net benefits from 1000 MW summer sale to California are estimated to be about $2.5 billion.

5.2 Region #2: Sask/Manitoba/U.S. Midwest

Table #4 shows the magnitude of the potential seasonal diversity and summer sales that exist between the combined Sask/Manitoba systems and the U.S. Midwest. The potential to make seasonal diversity exchanges appears reasonable since it involves the deferring of capacity only with net zero interchange of energy. However the likelihood of the combined Manitoba/Saskatchewan system to make large high load factor firm summer sales of a longer duration is very low for the following reasons. Manitoba Hydro is predominantly hydraulic with annual stage capability and thus energy limited. Saskatchewan, although mostly thermal, is not large and thus may not have significant surplus energy to support such sales. However, it is recognized that in those years where hydraulic conditions are favourable the opportunities for firm summer sales may exist. Based on these considerations we have assumed that only seasonal diversity exists and not long term summer sales between the Canadian and U.S. utilities in this region.

Tables #5 shows the corresponding net benefits from exploitation of the maximum potential seasonal diversity from these systems.

This analysis was based on the following assumptions:

<u>For Seasonal Diversity</u>

- 850 MW Seasonal Diversity exchange. Although the potential diversity is estimated at 850 MW, existing exchanges with Northern States Power now amount to 300 MW.

REGION #2 SASK/MANITOBA/U.S. MIDWEST

Table #4

Potential Magnitude of Seasonal diversity and Summer Sales

Systems	2000 Peak Load		Potential Capacity Sur. MW	Potential Diversity Exch. MW	Potential Sum. Sale MW
	Winter MW	Summer MW			
(1)	(2)	(3)	(4) = (2)-(3) s = summer w = winter	5 = (0.5)(4)	(6)=(4)
System Ch5. Combined Sask/Man	7 335	5 636	1699 (s)	850 (s)	1699 (s)
U.S. Midwest	24 573	28 454	3881 (w)	1940 (w)	3881 (w)
Pot. Diversity s/w Sask/Man & U.S. Midwest				850 (s/w)	1699 (s/w)

Table #5

Net Potential Benefits from Seasonal Diversity Exchanges
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Amount of Diversity MW	Capital Deferm. mills/KWh			Trans. Cost mills/KWh	Net Benefits mills/KWh	CUM PW Factor (1)	Net Benefits $billions
		Sask/Man	U.S. Mid West	Total				
	(1)	(2)	(3)	(4) = (3)+(2)	(5)	(6) = (4)-(5)	(7)	(8) = (1)(6)(7)
Sask/Man with U.S. Mid W.	850 (1)	41.1	36.3	77.4	10	67.4	96.5	$5.5 billion

(1) At present, there is a 300 MW seasonal diversity exchange with Northern States Power. The potential benefits therefore include these amounts

- The contract period was 30 years at 80% c.f.

- Capital deferment in the U.S. Midwest was lignite generation estimated at 36.3 mills/kW.h (i.e. 55.8 - 19.5).

- Capital deferment in Sask was lignite generation estimated at 38.7 mills/kW.h (i.e. 48.7 - 10.0).

- Capital deferment in Manitoba was hydro generation estimated at 43.5 mills/kW.h (i.e. 44.5 - 1.0).

- Combined capital deferment in Sask/Man assuming a 50/50 split was estimated at 41.1 mills/kW.h.

- The additional transmission required to affect the exchanges between Manitoba and US Midwest utilities was estimated to be 1000 km at 10 mills/kW.h. for each 1000 MW of transfer (i.e. similar to the Mandan Project).

Tables #5 shows that the net benefits from the maximum potential seasonal diversity exchanges of 850 MW is estimated at $5.5 billion.

5.3 Region #3: Man/Ontario/Québec/New York/ECAR

Table #6 shows the magnitude of the potential seasonal diversity exchanges (2500 MW) and summer sales (5000 MW) between Ontario and the East Central Area Reliability Coordination Agreement (ECAR). This region comprising, among others, the states of Michigan and Ohio appears to be a natural market for Ontario. The table also shows the potential diversity and summer sales trade between Québec and New York. (1440 MW and 2880 MW respectively).

For this broad brush analysis, it was assumed that Ontario would have better trade opportunities with ECAR, while the New York market would be served by Québec.

Ontario's generation at the margin is coal, and because this province has stringent acid gas emission criteria, any potential diversity exchanges or summer sales may not be fully exploited. In addition as ECAR is made up of many interconnected utilities, as well as

REGION #3 MANITOBA/ONTARIO/QUEBEC/NEW YORK/ECAR (1)

Table #6

Potential Magnitude of Seasonal diversity and Summer Sales

Systems	2000 Peak Load		Potential Capacity Sur. MW	Potential Diversity Exch. MW	Potential Sum. Sale MW
	Winter MW	Summer MW			
(1)	(2)	(3)	(4) = (2)-(3) s = summer w = winter	5 = (0.5)(4)	(6)=(4)
System Ch5.					
Ontario	29 207	24 163	5044 (s)	2522 (s)	5044 (s)
Quebec	35 260	21 025	14 235 (s)	7117 (s)	14 235 (s)
New York	28 110	30 990	2880 (w)	1440 (w)	2880 (w)
ECAR	85 756	91 251	5494 (w)	2747 (w)	5494 (w)
Pot. Diversity s/w					
Ont. - ECAR				2500 (s/w)	5000 (s)
Quebec - NY				1440 (s/w)	2880 (s)

Table #7

Net Potential Benefits from Seasonal Diversity Exchanges
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Amount of Diversity MW	Capital Deferm. mills/KWh			Trans. Cost mills/KWh	Net Benefits mills/KWh	CUM PW Factor	Net Benefits $billions
		Canada	U.S.	Total				
	(1)	(2)	(3)	(4) = (3)+(2)	(5)	(6) = (4)-(5)	(7)	(8) = (1)(6)(7)
Ont-ECAR	500	37.3	38.3	75.6	10	65.6	96.5	$3.2 billion
Que-NY	1440 (2)	47.1	38.3	85.4	10	75.4	96.5	$10.5 billion

Table #8

Net Potential Summer Benefits from Sales
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Amount of Summer Sale MW	Annual Energy Production			Energy Prod. Diff. 6 months	Capital Def. U.S.	Total Benefit mills/kWh	Trans. cost mills/kWh	Net Benefits mills/kWh	CUM(1) PW factor	Net Benefits $billions
		Canada	U.S.	Diff.							
	(1)	(2)	3	(4) = (3)-(2)	(5) = 0.5(4)	(6)	(7) = (6)+(5)	(8)	(9) = (7)-(8)	(10)	(11)= (1)(9)(10)
Ont-ECAR	1000	33.4	32.4			38.3	38.3	10.0	28.3	96.5	$2.7 billion

(1) The NERC East Central Area Reliability coordination Agreement (ECAR) has been included in this region for potential seasonal Diversity Sales with Ontario

(2) At present, there is an 800 MW diversity sale to NWPA. The maximum potential seasonal diversity benefits therefore include these amounts.

the fact that the scheduled maintenance of large generating units is preferred in the summer months, potential trade may be reduced further. Finally, even if transmission facilities were built to support these transactions, loop flows and other transmission bottlenecks may cause further restrictions. As a result, the expected seasonal diversity and summer sale potential are estimated to be 500 MW and 1000 MW respectively.

Table #7 shows the corresponding net benefits from the exploitation of this potential seasonal diversity exchange between these systems. Table #8 shows the corresponding potential summer sale net benefits between the respective Canadian and U.S. systems. These analysis were based on the following assumptions.

For Seasonal Diversity

- 500 MW seasonal exchange between Ontario and ECAR.

- 1440 MW seasonal exchange between Québec and New York. The maximum potential diversity exchange estimated at 1440 MW includes HQ's existing exchanges with NYPA of 800 MW.

- Capital deferments in Ontario based on new coal fired plants at 37.3 mills/kW.h (i.e. 70.7 - 33.4).

- Capital deferments in Québec based on hydro generation at 47.1 mills/kW.h (i.e. 48.1 - 1).

- Capital deferments in New York based on new coal plants at 38.3 mills/kW.h (i.e. 76.6 - 32.4).

- Capital deferment in ECAR is assumed to be new coal and similar to New York at 38.3 mills/kW.h.

- Additional transmission lines required to effect the exchange is estimated to be 1000 km at 10 mills/kW.h for each 1000 MW of transfer.

For Summer Sales

- 1000 MW summer sale by Ontario to ECAR.
- Energy production costs for Ontario is 33.4 mills/kW.h.
- Energy production costs for New York and ECAR is estimated at 32.4 mills/kW.h.

Table #7 and 8 show the corresponding net benefits between systems if the expected potential seasonal diversity exchanges or summer sales are realized. For the Ontario - ECAR systems, the net benefits are $3.2 billion and/or $2.7 billion respectively. For the Québec - New York systems seasonal diversity exchange, the net benefit is $10.5 billion.

It should be noted significant summer surplus capacity exists in Québec which might be used for seasonal diversity or summer sales to ECAR. Thus a combined Québec/Ontario diversity and/or summer sales to ECAR might allow Ontario and Québec to package their sales to maximize their benefits while at the same time share in the risks associated with such transactions.

5.4 Region #5: Que/NB/PEI/New England

Table #9 shows the maximum potential seasonal diversity and/or summer sales that exists between the combined NB-NS and New England systems. However because NE's winter and summer peaks are so close in magnitude coupled with the fact that unit maintenance is scheduled in the summer period the potential for seasonal diversity and summer sales have been reduced to 150 MW and 250 MW respectively.

Tables #10 and #11 provide rough estimates of the potential net benefits from the expected seasonal diversity exchanges and summer sales.

These analyses were based on the following assumptions

For Seasonal Diversity

- 150 MW summer/winter seasonal diversity exchange for 30 years at 80% seasonal capacity factor.

- Capital deferment in NE was coal at 44.9 mills/kW.h (i.e. 80.0 - 35.1).

- Capital deferment in NB was new coal fired generation at 43.7 mills/kW.h (i.e. 69.6 - 25.9).

- Capital deferment in NS was new coal fired generation at 42.5 mills/kW.h (i.e. 68.4 - 25.9).

- Additional transmission required to affect the exchanges between NB - NS and NE is estimated at 1000 km at 10 mills/kW.h for each 1000 MW of transfer.

For Summer Sales

In addition to the values listed above, the following assumptions were used.

- 250 MW summer sale by NB-NS to NE

- Energy production costs in NE = 35.1 mills/kW.h.

- Energy production costs in NB = 25.9 mills/kW.h.

- Energy production cost in NS = 26.2 mills/kW.h.

From Table #9 the maximum potential seasonal diversity exchanges and summer sales between NB and NE are estimated to be 150 MW and 250 MW respectively.

Tables #10 and #11 show that corresponding net benefits of potential seasonal diversity exchanges or summer sales are similar at approximately $1.0 billion.

REGION #5 QUE/NB/NS/PEI/NEW ENGLAND

Table #9

Potential Magnitude of Seasonal diversity and Summer Sales

Systems	2000 Peak Load		Potential Capacity Sur. MW	Potential Diversity Exch. MW	Potential Sum. Sale MW
	Winter MW	Summer MW			
(1)	(2)	(3)	(4) = (2)-(3) s = summer w = winter	5 = (0.5)(4)	(6)=(4)
System Ch5.					
New Brunswick	3 397	2 135	1262 (s)	632 (s)	1262 (s)
Nova Scotia	2 394	1 734	660 (s)	330 (s)	660 (s)
NEPOOL	24 840	25 331	491 (w)	245 (w)	491 (w)
Pot. Diversity s/w					
NB - NE				245 (w/s)	491 (s)

Table #10

Net Potential Benefits from Seasonal Diversity Exchanges
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Amount of Diversity MW	Capital Deferm. mills/KWh			Trans. Cost mills/KWh	Net Benefits mills/KWh	CUM PW Factor	Net Benefits $billions
		NB	NE	Total				
	(1)	(2)	(3)	(4) = (3)+(2)	(5)	(6) = (4)-(5)	(7)	(8) = (1)(6)(7)
NB with NE	150	43.7	44.9	88.6	10	78.6	96.5	$1.1 billion

Table #11

Net Potential Summer Benefits from Sales
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Amount of Summer Sale MW	Annual Energy Production			Energy Prod. Diff. 6 months	Capital Def. NE	Total Benefit mills/kWh	Trans. cost mills/kWh	Net Benefits mills/kWh	CUM(1) PW factor	Net Benefits $billions
		NB	NE	Diff.							
	(1)	(2)	(3)	(4) = (3)-(2)	(5) = 0.5(4)	(6)	(7) = (6)+(5)	(8)	(9) = (7)-(8)	(10)	(11)= (1)(9)(10)
NB to NE	250	25.9	35.1	9.2	4.6	44.9	49.5	10.0	39.5	96.5	$1.0 billion

APPENDIX 5

POTENTIAL INTERCONNECTION OPPORTUNITIES

1. INTRODUCTION

Potential benefits from utility interconnection may arise in various forms including reduction in generation reserves, short-term economy energy trade, and energy banking. Interconnections between systems allow utilities to share the generation reserves that must be installed to provide reliably and secure electricity to customers, thereby reducing the total amount of reserves that would have been required. Short term economy energy trade allows one system access to any surplus energy available on an interconnected system at a more economic rate than they could generate it themselves. This can occur when the marginal cost of generation on one system is significantly higher than on the other. Energy banking allows low cost "off-peak" generation from a predominantly thermal system to be stored by an interconnected hydro system to be later returned to the thermal system during peak hours when its marginal cost of generation is high. The necessary conditions for this to occur includes a significant difference between the thermal system's "on-peak" marginal cost of generation compared to its "off-peak" marginal costs, sufficient storage capacity in the hydro system for the surplus energy, and adequate transmission capabilities between the two systems.

2. ASSUMPTIONS

The amount that one system can rely on another for generation reserves is dictated by the interconnection transmission limits between two systems. It should be noted here that most interconnection Canadian utilities already have agreements in place allowing them to share generation reserves.

The amount of economy energy trade depends on marginal cost differences between the interconnected utilities, and the amount of surplus of the lower cost energy available for sale. Economy transactions will only take place when the difference between the marginal costs of the two systems is large enough to overcome the costs of transmission, resulting in benefits to both parties.

The amount of energy banking depends on the interconnected system's generation and operating characteristics, as well as its load characteristics. For example if one assumes that the "on peak" and "off peak" load periods are equal, then the maximum amount of energy banking will be equal to the intertie transfer capability operating at an equivalent 50% annual capacity factor. Actual system conditions however could reduce the energy banking potential significantly if the interconnected systems are both winter-peaking. In these instances the opportunities for energy banking during the winter peak load months could be limited.

3. BENEFITS AND COSTS FROM INTERCONNECTIONS

Based on the above underlying assumptions, the gross benefits from generation reserve sharing can be calculated as the savings from deferring capital on each system. The gross benefits from economy energy transactions can be calculated assuming there is a fuel savings on one of the system. The gross benefits from energy banking transactions can be calculated as the difference between the thermal system's "on" and "off" peak marginal generation costs. Costs on the other hand would be the added cost of transmission facilities required to make the transactions.

4. RESULTS FROM A REGIONAL PERSPECTIVE

Although some interconnection opportunities exist in all the regions outlined in this report, it is in Region #4 where significant opportunities appear to exist. For this reason, only Region #4 was assessed in this review.

4.1 Region #4: Ontario/Québec/New York/N England

In this region significant interconnection opportunities exist between Ontario and Québec, between Québec and New York and between Québec and New England. This analysis however focuses only on the interconnection opportunities between Ontario and Québec.

For this cursory analysis it was assumed that:

- Ontario and Quebec could rely on each other for 200 MW reserve, deferring capital on each of their systems at 15.5 mills/kWh (using combined cycle generation).

- economy energy transfers to Ontario could occur at the rate of 3000 GWh/year.

- economy energy savings in Ontario based on a 20% decrement of the cost of coal (0.2 x 33.4 = 6.7 mills/kWh)

- 1000 MW at 5% annual capacity factor for a period of 30 years would be banked by Québec for Ontario (450 GWh/year).

- The "on" peak energy in Ontario was estimated to be coal at 33.4 mills/kW.h.

- The "off" peak energy in Ontario was estimated to be nuclear at 7.1 mills/kW.h.

- Additional transmission required to affect the transactions was a 1000 MW HVDC back to back station estimated to cost 5 mills/kW.h for each 1000 MW of transfer (see appendix 3)

Table #1 shows that net benefits arising from generation reserve sharing, economy energy transactions, and energy banking are $0.6 billion in total.

REGION #4 ONT/QUE/NEW YORK/NEW ENGLAND

Table #1

Net Potential Benefits from Interconnection
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Characteristics	Amount	Capital Deferred			Energy Savings		Energy Banking Savings				Total Potential Benefits $billions	Trans Costs 1000 HVDC Conv $2000	NET BENEFITS $2000
			mills/kWh	CUM PW factor	$2000 (@80% CF)	mills/kWh	$2000	Energy Prod. costs (mills/kWh) on peak	off peak	difference	Total savings $2000			
		(1)	(2)	(3)	4) = (1)(2)(3	(5)	6) = (1)(3)(5	(7)	(8)	(9) = (7)-(8)	(10) = (1)(3)(9)	(11)	(12)	(13) = (11) - (12)
Ontario and Quebec	Reduction in generation reserves	200 MW (Ont) 200 MW (Que)	15.5 15.5	96.5 96.5	$0.3 billion $0.3 billion							$0.3 billion $0.3 billion		
	Economy Energy transactions	3000 GWh/year		13.76 (1)		6.7	$0.28 billion					$0.28 billion		
	Energy Banking (1000 MW @ 5% CF)	450 GWh/year		13.76 (1)				33.4	7.1	26.3	$0.16 billion	$0.16 billion		
											TOTAL	$1.04 billion	$0.48 billion (2)	$0.56 billion

(1) see Appendix 1, p. 1.13 - 30 years)
(2) transmission costs assumed 5 mills/kWh, 80% capacity factor

APPENDIX 6

POTENTIAL REGIONAL DEVELOPMENT OPPORTUNITIES

1. INTRODUCTION

This appendix provides an analysis of the net benefits that may exist from regional cooperation in electric power developments.

2. ASSUMPTIONS

From an engineering economic viewpoint, after taking into account the potential for demand side management and conservation, utilities must meet their forecast increase in customer demands by adding new supply capability, either through building generation themselves or through purchases from others if the economics are attractive enough. This approach assumes that considerations of international and/or interprovincial boundaries, federal provincial and state regulations and policies and other factors such as the environment, employment impacts etc although important would not alter that fundamental premise.

3. BENEFITS AND COSTS FROM REGIONAL DEVELOPMENT OPPORTUNITIES

Based on the above underlying premise, the net benefits from regional developments was calculated as the difference between the purchaser's and seller's generation costs minus the cost of transmission facilities necessary to affect the transactions.

4. RESULTS FROM A REGIONAL PERSPECTIVE

4.1 Region #1: BC/Alberta/California

Generation costs in both BC and Alberta appear to be significantly less than those in California. In addition from Figure 8 (see report), the annual capacity requirements in California by the year 2000 could be as high 1000 MW. Thus potential exists for a combined BC/Alberta development to meet the increasing demands in California.

For this analysis we have assumed that:

- BC/Alta sells California 1000 MW of firm capacity and associated energy at 80% c.f. for a period of 30 years starting in 2000.

- The total generation costs for BC based on coal fired generation is estimated at 50.2 mills/kW.h.

- The total generation costs for Alberta based on sub-bituminous coal fired generation is estimated at 32.6 mills/kW.h

- The combined BC/Alt total generation costs, assuming a 50/50 split is estimated at 41.4 mills/kW.h.

- The total generation costs in California based on natural gas fired generation is estimated at 89.9 mills/kW.h.

- Additional transmission required to affect the firm sales to California is estimated to be 2000 km at 20 mills/kW.h for each 1000 MW of transfer (see Appendix 3).

- Tables #1 provides rough estimates of the net benefits arising from this long-term firm power sales. These net benefits are estimated at $2.8 billion.

4.2 Region #2: Sask/Manitoba/U.S. Midwest

From figure #3 (see report) it can be seen that the total generation costs between the respective areas are reasonably close to preclude any significant opportunities for major joint generation developments.

4.3 Region #3: Manitoba/Ontario/Québec/New York

As generation costs between Ontario's nuclear plants and Québec's hydro plants are relatively comparable, opportunities for large scale firm purchases/sales are limited.

The government of Ontario's present policy is not to build for exports and in fact with respect to nuclear generation has imposed a moratorium in the Fall of 1990 related to the construction of new nuclear plants. This results in export dedicated nuclear plants being

REGION #1 BC/ALTA/CALIFORNIA

Table #1

Net Potential Benefits from Long Term Firm Trade
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Characteristics	Amount of Sale MW	Total Generation costs in mills/KWh			Trans. Cost mills/KWh	Net Benefits mills/KWh	CUM PW Factor	Net Benefits $billions
			Canada	U.S.	Difference				
		(1)	(2)	(3)	(4) = (3)-(2)	(5)	(6) = (4)-(5)	(7)	(8) = (1)(6)(7)
Combined BC/Alta sale to California	To defer natural gas generation in California	1000	41.4	89.9	48.5	20	28.5	96.5	$2.8 billion

REGION #3 MAN/ONT/QUE/NY/ECAR

Table #2

Net Potential Benefits from Long Term Firm Trade
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Characteristics	Amount of Sale MW	Total Generation costs in mills/KWh			Trans. Cost mills/KWh	Net Benefits mills/KWh	CUM PW Factor	Net Benefits $billions
			Canada	U.S.	Difference				
		(1)	(2)	(3)	(4) = (3)-(2)	(5)	(6) = (4)-(5)	(7)	(8) = (1)(6)(7)
Ontario sale to NW or ECAR	To defer coal in NY or ECAR	1000	55	76	21	5	16	96.5	$1.5 billion
	To defer natural gas in NY or ECAR	1000	55	93.5	38.5	5	33.5	96.5	$3.2 billion
Quebec sale to NY	To defer coal in NY	1000	48.1	76	27.9	5	22.9	96.5	$2.2 billion
	To defer natural gas in NY	1000	48.1	93.5	45.4	5	40.4	96.5	$4.0 billion

impractical at this time. Nevertheless firm export opportunities may exist with utilities in New York and those in the ECAR region since generation costs in Ontario, using nuclear generation, appear to be cheaper than New York's or ECAR's generation costs using coal. The same is true between hydro generation costs in Québec and coal or natural gas fired generation in New York.

We recognized that the planning period for the nuclear plants are currently estimated to be about 15 years so that the earliest in service date for such plants would be about 2005 and not 2000 (which was assumed in this study). Nevertheless because of the comparative nature of this analysis, the calculated benefits are not expected to significantly change with changes in service dates.

Figure #10 (main report) indicates that the annual capacity requirements in New York and ECAR is estimated to be about 660 MW/yr and 1100 MW/year respectively. The potential therefore exist for either Québec and/or Ontario securing long-term firm exports to meet New York's or ECAR's increasing load requirements.

For this analyses we have therefore assumed that:

- New York and/or ECAR each requires 1000 MW by the year 2000.
- Each of Ontario and Québec export to New York and/or ECAR a 1000 MW of firm capacity and associated energy at 80% c.f. for a period of 30 years starting in 2000.
- Total generation costs for Ontario is based on nuclear plants at 55.0 mills/kW.h.
- Total generation costs for Québec is based on hydro at 48.1 mills/kW.h
- Total generation costs for New York or ECAR is based on coal and/or natural gas fired plants at 76 mills/kW.h and 93.5 mills/kW.h respectively.
- Additional transmission required for firm sales to New York is estimated 500 km at 5 mills/kW.h for each 1000 MW of transfer for either Ontario or Québec.

Table #2 provides rough estimates of the net benefits resulting from these long-term power exports. For sales by Ontario to New York or ECAR the net benefits range from

$1.5 billion to $3.2 billion depending on whether the US alternative is coal or natural gas. Net benefits from Québec sales to New York on the other hand are estimated to range from $2.2 billion to $4.0 billion.

4.4 Region #4: Ont/Québec/Nfld/NY/NE

The generation costs for Gull Island and Muskrat falls in Labrador appear to be the lowest in this region. The combined capacity of these two hydro developments (about 3100 MW) appear to be too large for Newfoundland to readily absorb since that province's annual capacity requirement is estimated to be about 60 MW/yr by the year 2000.

A potential fast track development of Gull Island and Muskrat Falls might be, in addition to serving the Newfoundland's needs via an HVDC cable link, to also consider long-term firm sales with systems large enough to absorb the remaining output from these plants. These markets are Québec, NY state and/or New England.

Exploiting part of Labrador Hydro resources for export purposes raises a host of major considerations such as transmission access and wheeling through Québec etc. However even considering these formidable barriers it may be possible to reach an agreement.

In order to obtain same notional view of the net benefits that might be realized, the following development options were assumed.

Muskrat Falls and Gull Island with a combined capacity of 3100 MW would be developed for in service by the year 2000. A 950 MW HVDC line would be built to link these hydro resources to the Island of Newfoundland. The Island's share of these resources would be 800 MW. To that new supply would be added approximately 150 MW of recall power under the Churchill Falls contract available for the Island. Thus the total new supply to the Island is estimated at 950MW. These supply sources would be used to back off all the oil-fired generation on the Island (i.e. up to 650 MW from Holyrood #1-4).. The remaining 300 MW would be used to meet the Island forecast increase in loads. Without this infeed the Island's load requirements would continue to be met by oil-fired generation.

The surplus hydro remaining after Newfoundland's needs are satisfied is estimated to be 2200 MW. Of this surplus, it was assumed that in the first scenario Québec would

purchase 1000 MW in lieu of building in-province generation while 1200 MW would be exported to New England. This would allow New England to defer two 600 MW of coal-fired units. The second scenario has the total 2200 MW being purchased by Québec in lieu of building in-province generation. The third scenario sees only 1450 MW being purchased by Quebec, with the remaining 750 MW being purchased by Nova Scotia and New Brunswick to defer coal generation on their respective systems.

The basic assumptions for the first scenario are as follows:

- 800 MW supply from the Gull Island Muskrat Falls Complex plus 150 MW of Churchill falls recall power for a 30 year period starting in 2000.

- 1000 MW supply to Québec from the Labrador Complex for a 60 year period starting in 2000.

- 1200 MW supply to New England from the Labrador Complex for a 30 year period which is the maximum period of exports under the NEB Act. It is also equivalent to the life of a thermal plant (i.e. US alternative).

- The HVDC Labrador - Newfoundland link is estimated at 26 mills/kW.h (see Appendix 3).

- The total generation costs for Gull Island are estimated at 39.2 mills/kW.h (see Figure #3 of the report). These costs include 75% of the cost of the HVDC link. The comparable "at site" cost for Gull Island is thus estimated to be 19.2 mills/kW.h.

- The total Generation costs for Muskrat Falls including a 25% portion of the HVDC link to the Island is estimated at 44.7 mills/kW.h. The comparable "at site" cost for Muskrat Falls is thus 38.7 mills/kW.h.

- The total combined "at site" generation at the complex assuming a cost split proportional to the capacity of each plant is estimated at 24.7 mills/kW.h.

- Cost of generation in Québec is estimated at 48.1 mills/kW.h.

- Cost of generation in New England is estimated at 80.0 mills/kW.h and 101.5 mills/kW.h for coal and natural gas fired generation respectively.

- Cost of generation in Newfoundland based as oil fired generation estimated at 112.5 mills/kW.h with associated energy costs at 87.0 mills/kW.h.

- Hydro energy production costs are estimated at 1.0 mills/kW.h.

- Additional transmission between Labrador and the Québec load center was estimated to be 1000 km and to cost 10 mills/kW.h for each 1000 MW of transfer (see Appendix 3)

- Additional transmission between Labrador and the New England market (for the first scenario) was estimated to be 1500 km and to cost 15 mills/kW.h for each 1000 MW of transfer.

The basic assumptions for the second and third scenarios are the same as the above, with the exception of the supply to Québec. In scenario 2, 2200 MW would go to Québec, with no firm supply to New England. In scenario 3, 1450 MW would go to Quebec, 450 MW would go to New Brunswick, and 300 MW would go to Nova Scotia.

Tables #3(a), 3(b), and 3(c) detail the net benefits resulting from these development options. Benefits from scenario 1, with sales to Quebec and New England, could potentially reach $13.2 billion depending upon the type generation deferred in New England. Scenario 2 has sales only to Québec for deferral of hydro generation, and shows a benefit of $7.7 billion. Scenario 3 has sales to Québec, New Brunswick, and Nova Scotia, and shows a benefit of $8.8 billion. Both scenarios 2 and 3 result in all the benefits remaining in Canada.

4.5 Region #5: QUE/NB/NS/PEI/NE

Because generation costs in New Brunswick and Nova Scotia appear comparable, the opportunities for joint development do not appear to be large. Nevertheless, benefits may still exist from the staggering of generation additions for each province to effectively optimize the generation expansion program for the Maritimes as a whole. As for Prince Edward Island, opportunities for increased regional developements and/or interprovincial trade exist with New Brunswick and/or Nova Scotia if transmission access through NB

REGION #4 ONT/QUE/NFLD/NY/NE

Table #3(a) Scenario 1

Net Potential Benefits from Long Term Firm Trade
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Characteristics	Amount of Sale MW	Total Generation costs in mills/KWh							Trans Costs mills/kWh	Net Benefits mills/kWh	CUM PW Factor	Net Benefits $billion
			at site Lab complex		Total Costs	Defer or Displace Generation			Difference mills/kWh				
			Energy	Capacity		Energy	Capacity	Total					
		(1)	(2)	(3)	(4) = (3)+(2)	(5)	(6)	(7) = (6)+(5)	(8) = (7) - (4)	(9)	(10) = (8)-(9)	(11)	(12) = (1)(10)(11)
Labrador Power & Church recall to Nfld.	In lieu of new thermal generation on the Island and to back off thermal generation on the Island	300	1	23.7	24.7	87	25.5	112.5	87.8	26	61.8	96.5 (5)	$1.80
		500											
		150	1	23.7	24.7	87		87	62.3	26	36.3	96.5	$1.80
		(recall)								(1)			
			1		1	87		87	86	26	60.0	96.5	$0.90
		950										Sub Total	$4.5 billion
Lab. sales to Quebec	To defer hydro generation in Quebec	1000	1	23.7	24.7	1	47.1	48.1	23.4	10 (2)	13.4 (1)	113.3 (4)	$1.5 billion
Lab. sales to N. England	To defer coal genration in N. England	1200	1	23.7	24.7	35.1	44.9	80	55.3	15 (3)	40.3 (1)	96.5 (5)	$4.7 billion
												TOTAL	$10.8 billion
Lab. sales to N. England	To defer natural gas generation in N. England	1200	1	23.7	24.7	83.1	18.4	101.5	76.8	15	61.8	96.5	$7.2 billion
												TOTAL	$13.2 billion

(1) HVDC Link to Nfld. costs as per Appendix 3
(2) Transmission Lab. to Quebec
(3) Transmission Lab. to new England
(4) Based on a 60 year contract period
(5) Based on a 30 year contract period

Table #3(b) Scenario 2

Net Potential Benefits from Long Term Firm Trade
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Characteristics	Amount of Sale MW	Total Generation costs in mills/KWh: at site Lab complex Energy	at site Lab complex Capacity	Total Costs	Defer or Displace Generation Energy	Defer or Displace Generation Capacity	Defer or Displace Generation Total	Difference mills/kWh	Trans Costs mills/kWh	Net Benefits mills/kWh	CUM PW Factor	Net Benefits $billion
		(1)	(2)	(3)	(4) = (3)+(2)	(5)	(6)	(7) = (6)+(5)	(8) = (7) - (4)	(9)	(10) = (8)-(9)	(11)	(12) = (1)(10)(11)
Labrador Power & Church recall to Nfld.	In lieu of new thermal generation on the Island and to back off thermal generation on the Island	300	1	23.7	24.7	87	25.5	112.5	87.8	26	61.8	96.5 (4)	$1.80
		500											
		150 (recall)	1	23.7	24.7	87		87	62.3	26 (1)	36.3	96.5	$1.80
		1	1		1	87		87	86	26	60.0	96.5	$0.90
		950											
												Sub Total	$4.5 billion
Lab. sales to Quebec	To defer hydro generation in Quebec	2200	1	23.7	24.7	1	47.1	48.1	23.4	10 (2)	13.4 (1)	113.3 (3)	$3.3 billion
												TOTAL	$7.8 billion

(1) HVDC Link to Nfld. costs as per Appendix 3
(2) Transmission Lab. to Quebec
(3) Based on a 60 year contract period
(4) Based on a 30 year contract period

Table #3(c) Scenario 3

Net Potential Benefits from Long Term Firm Trade
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Characteristics	Amount of Sale MW	Total Generation costs in mills/KWh							Trans Costs mills/kWh	Net Benefits mills/kWh	CUM PW Factor	Net Benefits $billion
			at site Lab complex		Total Costs	Defer or Displace Generation			Difference mills/kWh				
			Energy	Capacity		Energy	Capacity	Total					
		(1)	(2)	(3)	(4) = (3)+(2)	(5)	(6)	(7) = (6)+(5)	(8) = (7) - (4)	(9)	(10) = (8)-(9)	(11)	(12) = (1)(10)(11)
Labrador Power & Church recall to Nfld.	In lieu of new thermal generation on the Island and to back off thermal generation on the Island	300	1	23.7	24.7	87	25.5	112.5	87.8	26	61.8	96.5 (4)	$1.80
		500											
		150	1	23.7	24.7	87		87	62.3	26	36.3	96.5	$1.80
		(recall)								(1)			
			1		1	87		87	86	26	60.0	96.5	$0.90
		950											
												Sub Total	$4.5 billion
Lab. sales to Quebec	To defer hydro generation in Quebec	1450	1	23.7	24.7	1	47.1	48.1	23.4	10 (2)	13.4 (1)	113.3 (3)	$2.2 billion
Lab. sales to NS and NB	to defer coal									(5)			
	Belledune (NB)	450	1	23.7	24.7	25.9	43.7	69.6	44.9	15	29.9	96.5	$1.3 billion
	Sheet Harbour (NS)	300	1	23.7	24.7	26.2	40.3	66.5	41.8	15	26.8	96.5	$0.8 billion
												TOTAL	$8.8 billion

(1) HVDC Link to Nfld. costs as per Appendix 3
(2) Transmission Lab. to Quebec
(3) Based on a 60 year contract period
(4) Based on a 30 year contract period
(5) Transmission Lab. to NB and NS

can be secured. For this analysis we have assumed a 50 MW coal fired and/or nuclear purchase by PEI from NB.

With respect to export trade, Figure # 6 (see report) shows that New England requires about 600 MW/year of additional capacity to meet its increased load requirements. Thus a combined NB/NS export of 1200 MW to NE from coal fired units in lieu of natural gas combined cycle generation in New England might offer opportunities for increased export trade.

Assumptions related to the above development schemes are detailed in the section that follows.

Interprovincial Trade opportunities

For the 50 MW long-term purchase by PEI from NB, the following assumptions were used.

- Generation costs for PEI is estimated at 154.4 mills/kW.h using oil fired combined cycle units (i.e. 2 X 25 MW).
- Generation costs for NB assumed to be Pt. Lepreau at 75.6 mills/kWh.
- No additional transmission would be required to affect these transactions since they are effectively a continuation of existing agreements.

International Trade Opportunities

NB/NS sells New England 1200 MW of firm capacity and associated energy at 80% c.f. for a period of 30 years starting in 2000.

- Generation costs in NE assuming natural gas fired generation are estimated at 101.5 mills/kW.h.
- Generation costs for NB assumed to be Pt. Lepreau at 75.6 mills/kWh, and for NS assumed to be Sheet Harbour at 66.5 mills/kWh.

- Additional transmission required to effect the firm sales to New England is estimated to be 1000 km at 10 mills/kW.h for each 1000 MW of transfer.

Table # 4 details the net benefits resulting from the interprovincial development options. Net benefits from PEI 50 MW purchase from NB are calculated at $0.4 billion.

Table # 4 also shows that the net benefits from combined NB/NS 1200 MW export sale to NE is estimated at $2.3 billion. However, such deals may be difficult to realize because of the factors used by NE in their evaluation of projects. In particular, emission externalities make natural gas the fuel of choice and may override the benefits from purchases identified above.

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Table #4

Net Potential Benefits from Long Term Firm Trade
(All values in $ of 2000 using a real discount rate of 6%)

Systems	Characteristics	Amount of Sale MW	Total Generation costs in mills/KWh			Trans. Cost mills/KWh	Net Benefits mills/KWh	CUM PW Factor	Net Benefits $billions
			Lepreau #2 Nuclear	Gen. displaced	Difference				
		(1)	(2)	(3)	(4) = (3)-(2)	(5)	(6) = (4)-(5)	(7)	(8) = (1)(6)(7)
INTERPROVINCIAL NB sale to PEI	In lieu of PEI GT's	50	75.6	154.4	78.8		78.8	96.5	$0.4 billion
INTERNATIONAL Combined NB-NS sale to NE	To defer natural gas generation in NE	600	75.6	101.5	25.9	10	15.9	96.5	$0.9 billion
		600	66.5	101.5	35.0	10	25.0	96.5	$1.4 billion
		1200							$2.3 billion